AD-781 816

ASSESSMENT OF TOTAL ENERGY SYSTEMS FOR THE DEPARTMENT OF DEFENSE - VOLUME 1

STANFORD RESEARCH INSTITUTE

PREPARED FOR

DEFENSE ADVANCED RESEARCH PROJECTS AGENCY

NOVEMBER 1973

DISTRIBUTED BY:

NTIS

National Technical Information Service

U. S. DEPARTMENT OF COMMERCE

UNCLASSIFIED
Security Classification

AD-781 816

DOCUMENT CONTROL DATA - R & D

(Security classification of title, body of abstract and indexing annotation must be entered when the overall report is classified)

1. ORIGINATING ACTIVITY *(Corporate author)* Stanford Research Institute, Menlo Park, California 94025	2a. REPORT SECURITY CLASSIFICATION Unclassified
	2b. GROUP n/a

3. REPORT TITLE
ASSESSMENT OF TOTAL ENERGY SYSTEMS FOR THE DEPARTMENT OF DEFENSE - VOLUME I

4. DESCRIPTIVE NOTES *(Type of report and inclusive dates)*
Final Report

5. AUTHOR(S) *(First name, middle initial, last name)*
Richard L. Goen

6. REPORT DATE November 1973	7a. TOTAL NO. OF PAGES 115	7b. NO. OF REFS

8a. CONTRACT OR GRANT NO. DACA 23-73-C-0014	9a. ORIGINATOR'S REPORT NUMBER(S) SRI Project EGU-2513
b. PROJECT NO.	
c. Program Code No. 3F10	9b. OTHER REPORT NO(S) *(Any other numbers that may be assigned this report)*
d. ARPA Order No. 2408	

10. DISTRIBUTION STATEMENT
Unlimited

11. SUPPLEMENTARY NOTES	12. SPONSORING MILITARY ACTIVITY Defense Advanced Research Projects Agency

13. ABSTRACT

The purpose of this study is to assess the potential applicability of various types of total energy systems to military installations. The types of energy systems considered include diesel, gas turbine, steam turbine, geothermal, solar, nuclear, and solid wastes. Fuel savings are given for each type of system, and their costs are compared with the costs of conventional systems. The two most promising systems are (1) solar energy applied to heating and cooling, and (2) nuclear power.

UNCLASSIFIED
Security Classification

14 KEY WORDS	LINK A		LINK B		LINK C	
	ROLE	WT	ROLE	WT	ROLE	WT
Total energy						
Solar energy						
Nuclear power						
Geothermal						
Fuel consumption						
Energy system costs						

DD FORM 1 NOV 65 1473 (BACK)
(PAGE 2)

ia

UNCLASSIFIED
Security Classification

STANFORD RESEARCH INSTITUTE
Menlo Park, California 94025 · U.S.A.

Final Report

November 1973

ASSESSMENT OF TOTAL ENERGY SYSTEMS FOR THE DEPARTMENT OF DEFENSE

Volume I

By: RICHARD L. GOEN

SRI Project EGU-2513

ARPA Order No. 2408

Program Code No. 3F10

Name of Contractor:
Stanford Research Institute
333 Ravenswood Avenue
Menlo Park, California 94025

Principal Investigator (SRI):
Robert M. Rodden
Phone (415) 326-6200, Ext. 3959

Project Engineer (CERL):
John Pollock
Phone (217) 352-6511, Ext. 491

CONTRACT DACA 23-73-C-0014
Date of Contract: 12 March 1973
Contract Expiration Date: 31 December 1973
Amount of Contract: $228,854

This research was supported by the Defense Advanced Research Projects Agency of the Department of Defense and was monitored by the Construction Engineering Research Laboratory of the Corps of Engineers.

ABSTRACT

The purpose of this study is to assess the potential applicability of various types of total energy systems to military installations. The types of energy systems considered include diesel, gas turbine, steam turbine, geothermal, solar, nuclear, and solid wastes. Fuel savings are given for each type of system, and their costs are compared with the costs of conventional systems. The two most promising systems are (1) solar energy applied to heating and cooling, and (2) nuclear power.

CONTENTS

Preceding page blank

ILLUSTRATIONS

TABLES

Preceding page blank

PREFACE

This study was conducted in the Operations Evaluation Department, George D. Hopkins, Director, of SRI's Engineering Systems Division. The program manager was Robert M. Rodden, and the project leader was Richard L. Goen. The work on geothermal resources was conducted by Richard Schmidt, and the geothermal costing by Ronald K. White. John W. Ryan calculated the fuel consumption and much of the system costs. Jack E. Van Zandt of the Institute's Urban and Social Systems Division collected the data on military installations and developed the energy load profiles. Edwin M. Kinderman, Physical Sciences Division, worked on the solar energy systems.

Work on the study was also performed under subcontracts to Bechtel Corporation and Decision Sciences Corporation. Larry O. Beaulaurier and Gordon Stout of Bechtel Corporation prepared the performance characteristics and costs of the fossil fuel systems (Appendix A). James L. Oplinger of Decision Sciences provided modeling procedures and energy load data.

The study was conducted for ARPA under the cognizance of Rudolph A. Black. Richard G. Donaghy of the U.S. Army Construction Engineering Laboratory was the authorized representative of the contracting officer, and John Pollock was the contract monitor.

Extensive information gathering was conducted early in the study, and valuable contributions were provided by many individuals, only a few of whom can be mentioned here. Arrangements and required clearances for visits to military installations were handled by John Pollock of CERL for the Army, James Boatwright and Harold Pfreimer of the Air Force Engineering Division for the Air Force, and Carl Hershner and Wayne Lorimor of

Preceding page blank

NAVFAC for the Navy. Facilities summary information was obtained from David Crabtree for the Army and A. M. Crawford, Jr., for the Air Force.

Other major contacts include Thomas Casberg, DoD Installations and Logistics; Charles Smith, John Hoffmann, and Takeshi Kumagai of the Army Power Group; Gerald Leighton, Department of Housing and Urban Development; Clinton Phillips and Bert Coble, National Bureau of Standards; and Paul Jones, Gulfport, Mississippi, and George Davis, Washington, D.C., of the U.S. Geological Survey.

This contract includes another study, "Energy Data Management," which is not covered in this report.

Volume I of this report summarizes the results of the study. Volume II contains appendices with backup information.

I SUMMARY

Purpose

The purpose of this study is to assess the potential applicability of various types of total energy systems to military installations. The problem of energy shortages is widely recognized. The objectives of the study are to determine the potential energy savings that could be obtained with the different types of energy systems, the costs of the systems, and the conditions in which the systems would be attractive.

Scope

Normal peacetime energy uses of permanent military installations are considered; energy systems for emergencies or special military functions are excluded, as are mobile applications such as trucks or airplanes.

The term "total energy" (TE) is commonly used to refer to systems that generate electricity on-site, and make use of the heat recovered from electric generation for hot water, space heating, air conditioning, and other purposes. Since about two-thirds of the energy used in generating electricity is commonly exhausted as waste heat, the utilization of this heat offers the possibility of substantial energy conservation as well as reduction in the environmental impact of the waste heat release. There are several hundred TE systems operating in the United States in applications such as housing developments, shopping centers, and hospitals. The energy systems covered in this study are broader in scope than the type of systems commonly included in the TE category.

The selection of energy systems to study was based in part on considerations of relatively near-term applicability. The energy systems included in the study are as follows:

Fossil fuel systems
- Conventional
- Diesel electric
- Gas turbine
- Steam turbine

Geothermal
- Dry steam
- Hot water
- Geopressure

Solar thermal conversion
- Heating and cooling only
- Electric generation plus heating and cooling

Nuclear

Solid wastes.

The exclusion of other possible energy systems does not imply any judgment of their merits. Combined cycle systems (gas turbine plus steam turbine) were excluded because the high ratio of thermal loads to electric loads permits utilization of most of the recoverable heat from the gas turbine. Other notable exclusions are: fuel cells, photovoltaic (solar cells); magnetohydrodynamics, breeder reactors, fusion, wind, and ocean thermal gradients.

Methodology

Information was collected on the energy consumption of military installations. From this information, representative energy load profiles were developed for three climatic regions.

The performance characteristics of the major groups of equipment for the various energy systems were determined, and estimates were made of

the installed costs and operating costs excluding fuel. A variety of TE configurations were synthesized to meet the energy loads.

A fuel consumption model was developed, and fuel consumption both for electricity generation and auxiliary heating was calculated for all cases.

The initial costs were annualized using the standard DoD discount rate and added to the annual operating costs. Fuel costs were treated parametrically. Graphs were prepared to compare the costs of TE systems with the costs of conventional systems.

Fuel Savings

The potential fuel savings with each type of energy system, compared with a conventional system, are shown in Figure 1. The fuel consumption of the conventional system consists of the fuel consumed on base for the various heat uses, plus the fuel consumed by the utility in generating the electricity for the base, assuming a heat rate of 10,000 Btu per kWh.

Both nuclear and geothermal power systems could provide 100 percent of the electric power and heat needs of a military installation, excluding the downtime for a nuclear power plant. (Downtime has been included in the evaluation of all types of energy systems.)

The savings in fuel from using solar energy depend on the sizes of the solar collectors and the thermal storage. With moderate sizes of collectors and storage, a solar energy system used for generating electricity and for heating and cooling can meet well over half of the energy needs of a base. A solar system used only for heating and cooling can provide nearly half of those needs.

Next in potential for fuel savings is a TE system using a single large gas turbine, operated to meet the thermal loads of the base with

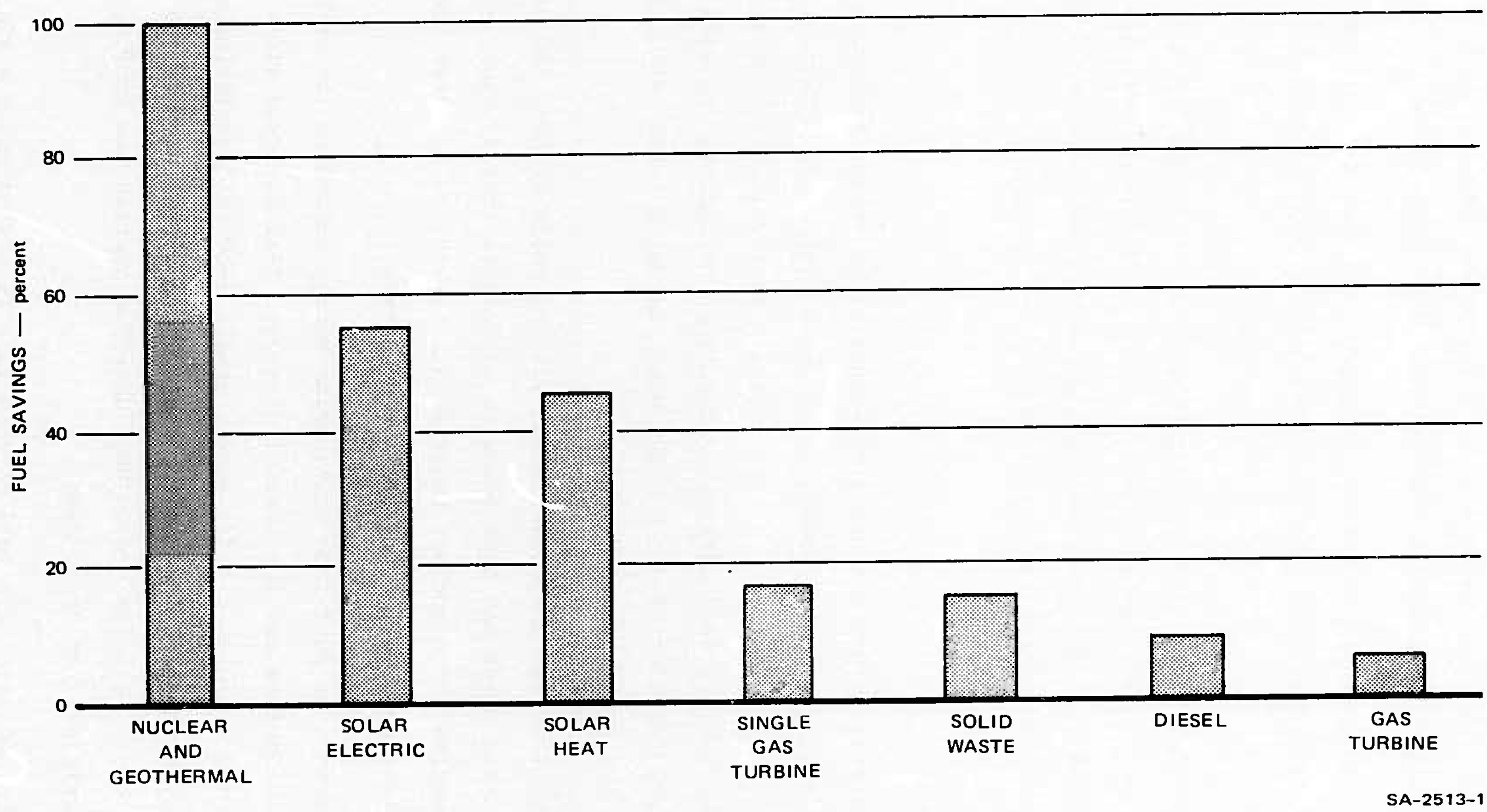


FIGURE 1 POTENTIAL FUEL SAVINGS OF NEW ENERGY SYSTEMS COMPARED WITH CONVENTIONAL SYSTEM

the recoverable heat from electricity generation, and sending the excess electricity off base. Here potential fuel savings over conventional systems range from 15 to 23 percent, depending on base size, gas turbine size, and climate.

The solid wastes produced on military installations could provide from 10 to 40 percent of the energy required for heating, excluding electric power requirements. In some cases the solid wastes could provide the fuel needed to supplement a solar energy system used for heating and cooling. Thus, energy from solid wastes and solar energy are complimentary, and the combination appears attractive.

The most common type of TE system consists of a diesel or gas turbine power plant, with multiple generating units, operated to meet the electric load and utilizing the recoverable heat from the electric generation. The energy demands of the military installations for heating and cooling greatly exceed the heat recoverable from the electric generation. The potential fuel savings range from about 5 to 10 percent, depending on type of operation, base size, climate, and type of air conditioning. (A commonly quoted figure of 30 percent fuel savings for such systems means 30 percent of only the fuel used to generate electricity.)

The fuel savings for a steam turbine (not shown in Figure 1) are as high as 10 percent for the largest bases in the colder climates, but entail a fuel penalty, instead of savings, for smaller bases in warmer climates.

Conclusions

Diesel and Gas Turbine Systems

The comparison of costs of these TE systems with the costs of a conventional system is primarily dependent on the relative increases in fuel and electricity prices over the system lifetimes. If the price of fuel used by the utility to generate electricity is about the same as the price

of the fuel used by a TE system, then the TE system will have a lower total annual cost than a conventional system. However, electricity costs may not increase in proportion to the increase in the prices of oil or natural gas used by the TE systems, since the electric power from the utility may be generated by nuclear power or coal. If the fuel cost element in the electricity price does not increase almost as much as the fuel prices for the TE system, then the TE system will have a higher total cost.

The relatively small energy savings, probable higher annual cost, and increased consumption of scarce oil fuel, of the independent, multiple generating unit diesel and gas turbine TE systems make them of little interest for military installations. In some areas with high electric power costs, such a TE system might be suitable for incorporation in a new building complex. A diesel system would be preferable to a gas turbine system because of the greater fuel saving. It should be sized to provide electricity to a larger portion of the base than is served by the recoverable heat.

The large single unit gas turbine TE system provides greater potential fuel savings, but has the other disadvantages of the multiple unit TE systems. Also, a major portion of a large base must be connected to the system to utilize it fully.

Solar Energy

The comparison of the cost of a solar energy system for heating and cooling, with the cost of a conventional system, is primarily dependent on fuel costs and the costs of solar collectors. Although both these costs are uncertain, it appears likely that low enough costs can be achieved for solar collectors, and that fuel costs will increase sufficiently, to make solar energy economically attractive.

Solar energy systems for generating electricity as well as for heating and cooling may also be attractive, but their technology and costs are even more uncertain.

Geothermal Potential

Although there are only a few major bases in the United States in areas with geothermal potential of the dry stream, hot water, or geopressure type, development of these resources could represent a positive contribution to energy supply. However, it is not known which of these bases could actually be expected to have geothermal energy available. The costs of a geothermal TE system would be very attractive if the technological problems of corrosives and solids in the fluids can be solved.

There is limited availability of these better known types of geothermal resources. Geothermal energy would be of major interest to DoD if the more wide-spread dry, hot rock sources could be utilized. These are quite imperfectly known and were not included in the present study.

Nuclear Power

Current cost information is not available for nuclear plants in the size range required for military installations. However, extrapolation of past cost data indicates that, with the expected increases in fossil fuel costs, nuclear power could be economically competitive. The applicable size range for the nuclear plants is 200 to 500 MWt.

Problems of safety and environmental considerations for siting nuclear plants on military installations were not addressed in this study.

Implications

The two most promising energy systems are (1) solar energy used for heating and cooling and (2) nuclear power. Utilization of solid wastes for heating should also be developed.

It is recommended that a program be undertaken for application of solar energy to heating and cooling on military installations. The first step should be a study to identify and evaluate alternative concepts and means of integration of solar energy elements into the military installations. This study should be followed by a prototype solar energy system on a military base.

A development program for nuclear power plants for use on military installations is also recommended. A system requirements study is needed to provide a basis for such a development program.

Further study of geothermal potentials for those facilities in favorable locations is also warranted.

II THE ENERGY SYSTEM MODEL

Description of the Study

The elements of the study and their relationships are indicated in Figure 2.

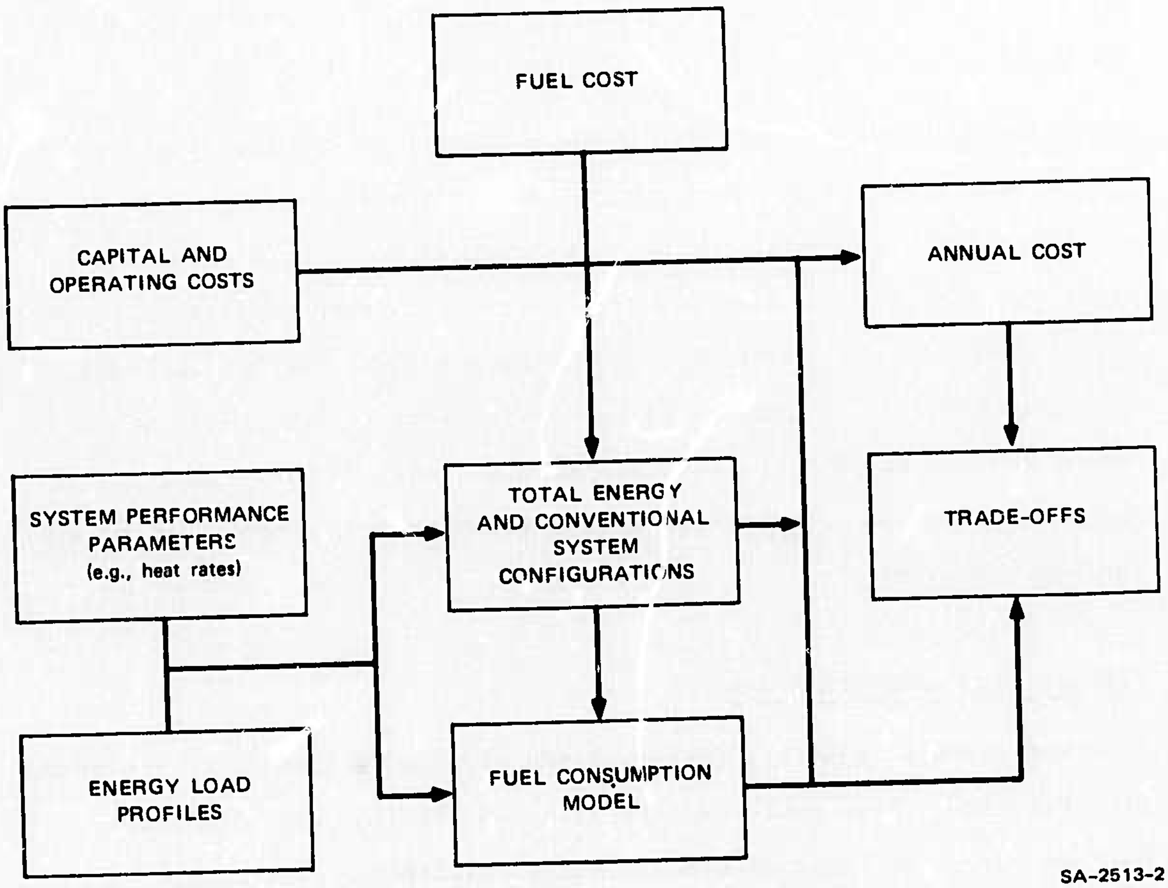


FIGURE 2 ENERGY SYSTEM MODEL

The initial step was the development of energy load profiles for military installations. These load profiles are described in Section III, and their derivation is given in Appendix B. Concurrently, the performance characteristics of the various types of energy systems were determined and then used to synthesize a variety of total energy configurations that would meet the energy loads. As a basis for comparison, conventional systems using utility electricity were included.

A fuel consumption model was developed, and fuel consumption both for electricity generation and auxiliary heating was calculated for all the cases.

Capital costs of installed major component groups for each type of system were compiled and used for the derivation of capital costs for each energy system configuration. The capital costs were annualized, using the standard DoD discount rate. The annualized capital costs were added to the annual operating and maintenance costs (excluding fuel) and fuel costs (with unit fuel costs as a parameter) to give total uniform annual costs. Graphs were then prepared to show the conditions for which the costs of total energy (TE) systems would be lower than those of conventional systems.

Military Installation Model

The sizes of military installations were characterized by the peak electric rate. Four peak electric rates--5, 10, 20, and 40 MW--were used to cover the range of sizes. Every installation was considered to consist of a number of complexes of buildings. For a conventional system, each complex was assumed to have both a central heating and an air conditioning system.

For the cases of centralized TE systems, the systems consist of a central electric generation plant and auxiliary heating, with both the

heat recovered from the electric generation and the auxiliary heat transmitted to the complexes by high temperature hot water lines. Chillers for the air conditioning are not centralized but rather are located in each complex, and, in the case of absorption air conditioners, are operated by the heat from the hot water lines.

The heating and cooling distribution system within each complex is excluded from the costing, on the assumption that this element would be approximately equal for the TE and conventional systems.

The following tabulation gives the number of complexes, the number of hot water heat transmission lines, and the lengths of each line assumed for the four sizes of bases:

	Base Size (peak MW)			
	5	10	20	40
Number of complexes	4	6	12	18
Hot water transmission lines	2	3	4	6
Line lengths (miles)	1	1.5	2	2.5

The line lengths are based on typical figures for the built-up area of military installations. Actual line lengths vary widely among bases, and therefore would introduce too many variables in this study. However, limited consideration is given to the effect on costs of variation in hot water line length.

Alternative Operating Concepts

A variety of operational concepts are considered. The primary emphasis is on centralized self-sufficient total energy systems, diesel and gas turbine, that are entirely independent of utility electricity. Multiple electric generating units are required for these cases to allow

for equipment downtime and load variations: six generating units are used for the diesel systems and seven for the gas turbine.

A self-sufficient TE system with dispersed generating units, one in each complex, is also considered. The generating units are electrically connected but there is no heat transmission between complexes. The reason for considering this concept is that it eliminates the costs of the hot water lines between the generating plant and the complexes.

Another alternative considered is intermediate between these two concepts. It consists of a self-sufficient centralized electric generating plant providing electricity for all of the base. However, the centralized heating system serves only part of the base, the rest being served by individual heating systems. Since the heat recovery from electric generation is usually much smaller than the heat load, most of the recoverable heat can still be utilized, thus reducing the costs of the hot water lines.

Electric generating plants dependent on utility electricity for downtime are also considered for the steam turbine and gas turbine. In this case single large generating units can be used, providing greater efficiency and lower capital costs per unit of capacity. Two variations of this case are: (1) sizing and operating the electric generating unit to meet the electrical load of the military installation, and (2) sizing and operating the electric generating unit to meet the thermal load with the heat recovered from the electric generation, and sending the excess electricity off site into the utility network. The first variation is used with the steam turbines and the second with the gas turbines.

Possible drawbacks to the utility-dependent concepts are the high demand charge for an electric load imposed only a small percent of the time, and the possible unwillingness or inability of an electric utility to provide such a service which increases their capacity requirement

without proportionate increase in sale of electricity. However, the on-site TE system could be owned and operated by the utility instead of the base. San Diego Gas and Electric Company has a TE installation at the Naval Training Center in San Diego; a 20 MW gas turbine-generator supplies electricity for the utility's electric system, and a heat recovery boiler produces steam for the Naval Training Center and the Marine Corps Recruit Depot. However, for costing purposes in this study, the TE installations have been considered as DoD owned and operated.

Performance Characteristics and Cost Elements of Fossil Fuel Systems

Detailed information was needed on the performance characteristics of the major elements of fossil fuel energy systems so that the elements could be combined into complete systems and fuel consumption could be calculated. The performance characteristics and cost information had to be developed in such a way that the system elements could be sized and combined to cover the many variations in base size, climate, and energy system configuration. The systems were divided into the following four component groups:

(1) Electric generating plant, consisting of the prime mover, electric generator, heat recovery system, building, and controls.

(2) High temperature water generator for the additional heat needed above that recoverable from the electric generation.

(3) Hot water transmission lines to transmit heat to the building complexes.

(4) Chillers for air conditioning.

The performance characteristics and costs for each of these four component groups are given in Appendix A. Many results are presented there as functions of unit capacity. Performance characteristics for the electric generation (diesel, gas turbine, and steam turbine) include:

Heat rates (Btu per kWh) at rated load

Heat rate multiplier to account for partial load

Waste heat recovery rate (MWt per MWe) at rated load

Waste heat recovery multiplier to account for partial load.

For the high temperature water generator, the characteristic needed for calculating fuel consumption is efficiency, which varies slightly with the type of fuel. Pump power and heat loss are given for the hot water transmission lines. For the air conditioning chillers, the energy (electric or heat) required per unit of refrigeration is given for electric, simple absorption, and double effect absorption air conditioning.

Capital costs are given in terms of installed cost per unit of capacity, as a function of unit capacity. Maintenance and operating costs, excluding fuel, are presented in a variety of ways.

System Synthesis

The information on performance characteristics of the four component groups given in Appendix A can be used to size and cost the equipment in each category to meet any given energy load profile. The considerations involved in synthesizing a system from the four component groups are illustrated in Figure 3.

The required electric generating capacity is based on the peak electric load, including (1) electricity for air conditioning if part of the air conditioning is electric, (2) an allowance for equipment downtime, and (3) the minor consideration of pump power for the hot water transmission line. The auxiliary heating capacity depends on the maximum differential between the thermal load (with allowance for heat loss in the hot water transmission line) and the recoverable heat from electric generation. The hot water transmission line capacity depends on the peak thermal load, with allowance for heat loss, and consideration of

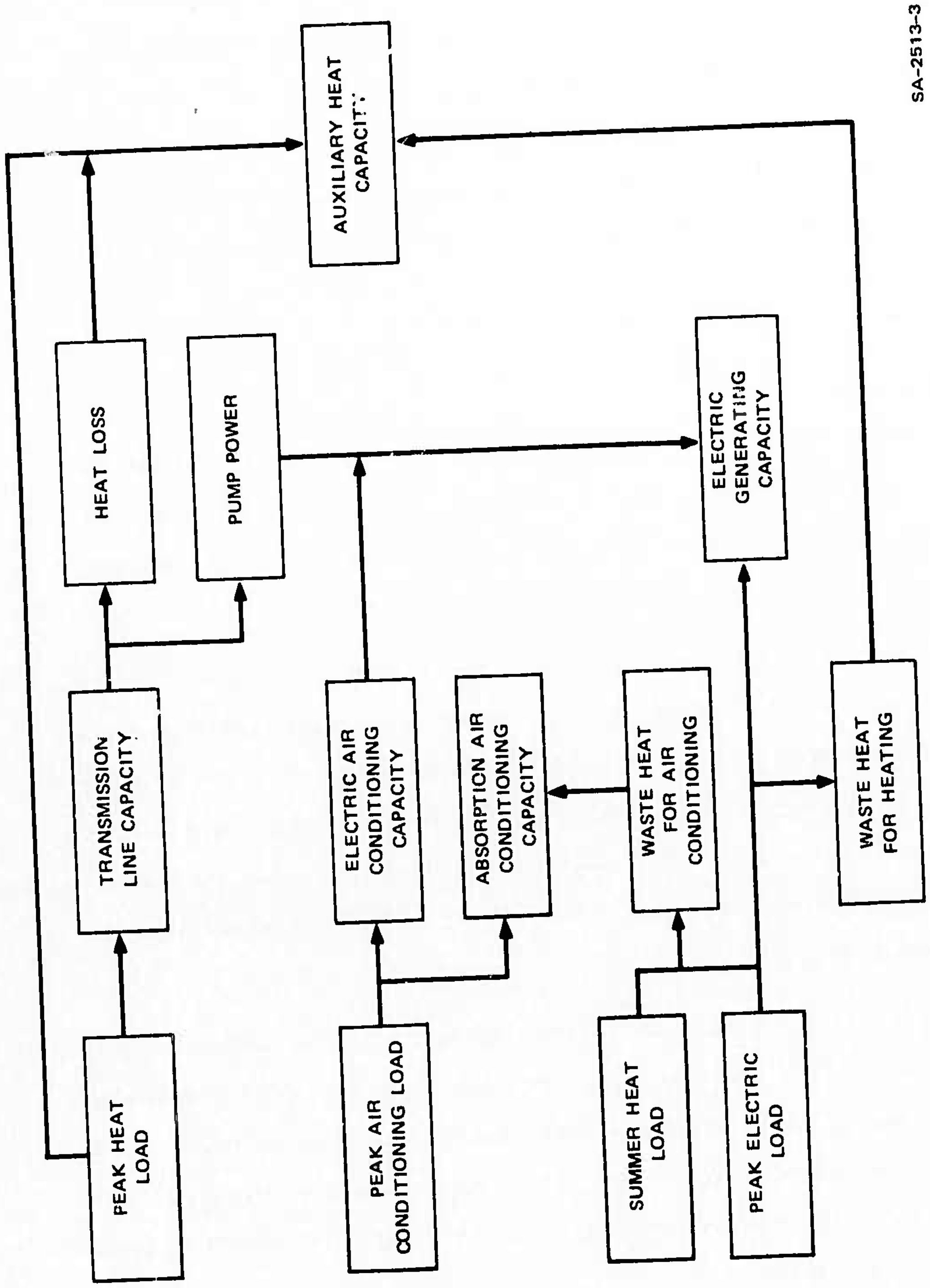


FIGURE 3 SYSTEM SYNTHESIS

reductions in size as hot water is extracted at the load centers (building complexes). For air conditioning there is a choice among electric, absorption, and double effect absorption chillers. Use of absorption chillers is desirable if they can be operated by the heat recovered from the electric generation. Otherwise electric chillers consume less energy. However, electric air conditioning increases the peak electric load, thus increasing the required capacity of the electric generating plant.

Cases Covered

The fossil fuel system cases covered in the study are shown in Table 1. The cases cover four base sizes and three climates but to reduce the number of cases, most of the variations were done only for the Southeast climate, an intermediate energy pattern.

For the self-sufficient, multiple generating unit, diesel and gas turbine cases, the variations in the amount and type of absorption air conditioning ranged from 10 percent to 100 percent, with the remainder electric air conditioning. Cases with dispersed generating units, and with heat transmission to only part of the base were also included. Limited consideration was also given to the effects of variations in the air conditioning load.

TE systems with single unit steam turbines or gas turbines, partially dependent on utility electricity, were also covered. Only large size steam turbines--25 MW and 40 MW--were included because of the reduced efficiency and sharply higher capital costs per unit of capacity for smaller sizes. The conventional system cases were included for comparison with the TE systems.

Table 1

TE AND CONVENTIONAL CASES COVERED, BY CLIMATE TYPE AND BASE SIZE

Type of System	MW:	North Central				Southeast				Southwest			
		5	10	20	40	5	10	20	40	5	10	20	40
Self-sufficient, multiple generating units													
Diesel													
Conv AC 10% absorp						X	X	X	X				
50%						X	X	X	X				
Double effect 10%						X	X	X	X				
50%		X	X	X	X	X	X	X	X	X	X	X	X
100%						X	X	X	X				
Dispersed						X	X	X	X				
Partial base								X					
Gas turbine													
Conv AC 50% absorp						X	X	X	X				
Double effect 50%		X	X	X	X	X	X	X	X	X	X	X	X
100%						X	X	X	X				
Dispersed						X	X	X	X				
Partial Base								X					
AC load variations								3					
Conventional system													
Electric AC		X	X	X	X	X	X	X	X	X	X	X	X
Double effect AC						X	X	X	X				
AC load variations								4					
Steam turbine*				X	X			X	X			X	X
Single gas turbine													
Double size				X			X	X	X			X	
Other size								2					

*25 MW instead of 20 MW.

Fuel Consumption Model

A model was developed to calculate the annual fuel consumption for the total energy systems. A computer program was needed primarily to calculate how much of the heat recoverable from the electric generation could be utilized. A flow diagram, program listing, and user instructions for the program are given in Appendix F--Volume II of this report.

The inputs to the model include (1) energy load profiles giving the hour-by-hour electric, thermal, and air conditioning loads for representative days of the year, (2) the heat rate and heat recovery rate for the electric generation plant, (3) the efficiency of the high temperature water generator and the air conditioning units, (4) the heat loss and pump power for the hot water lines, and (5) the equipment capacities.

The model calculates hour-by-hour the total electric and thermal loads, including system losses and the electric or thermal load for the air conditioning, from which the fuel consumption for electricity generation and auxiliary heat generation are calculated. The output includes the annual fuel consumption and also shows how much of the recoverable heat from the electric generation is utilized.

The conventional systems that are compared with the TE systems are those which use electricity from a utility and burn fuel for thermal needs. Fuel consumption for the heat generation is simply the total heat load divided by the efficiency of the high temperature water generator. An equivalent fuel consumption to account for the energy required to produce the electricity was based on a typical heat rate for large central station power plants of 10,000 Btu per kWh.

Costing

The standard DoD costing procedures were used in the study. Capital costs were annualized at a 6-1/8 percent discount rate, which was the current figure for utility systems at the time the cost work was begun

in late summer of 1973. The standard lifetime of 25 years for the equipment was used. The annual operating and maintenance costs, excluding fuel, were added to the annualized capital costs. The uniform annual cost of fuel over the 25 year period was then added as a parameter, because of the uncertainty in predicting future fuel costs. All the costs shown in this report are in constant 1973 dollars.

For conventional systems, the cost of purchased electricity was added to the above costs. This cost is made up of a demand charge based on the peak electric rate, and an energy charge based on the electricity used. The demand charge was considered to be constant while the energy charge was treated as a parameter to account for future increases in electricity prices as fuel prices increase.

III ENERGY LOADS AT MILITARY INSTALLATIONS

Sources of Data

Energy load patterns were needed for the evaluation of fuel consumption and costs of the different types of energy systems. Representative energy load profiles were derived from actual data on military installations, including (1) annual reports by the headquarters of each of the three services, and (2) interviews with engineering and utility personnel at several military bases. The annual reports provided the annual fuel and electricity consumption for most of the bases. At the individual bases data were obtained on peak energy loads, monthly fuel and electricity consumption, and diurnal fuel and electricity demands for a few selected days. However, there was little information on energy consumption by type of use. Most of the information collected was for FY 1972.

Peak Electric Demand

The sizes of the bases were characterized by their peak electric demand. Although the annual summary reports do not give this information, it was obtained directly from the bases visited, and was estimated for other bases from the annual electric consumption and the known correlation between peak electric demand and annual consumption.

Table 2 gives the distribution of the 70 bases according to peak electric demand. The largest concentration is in the 10 to 20 MW size range, and the median is 14 MW.

Preceding page blank

Table 2

RANGE OF PEAK ELECTRIC DEMAND AT MILITARY BASES

Base Size (MW)	Number of Bases
40-50	4
30-40	5
20-30	11
10-20	31
5-10	11
1-5	8
Total sample	70

Median 14 MW
Average 17 MW

Annual Energy Loads

A representative set of energy loads was derived for three types of climates--North Central, Southeast, and Southwest. The three components of the load are (1) thermal, (2) electric, and (3) air conditioning. The thermal and electric loads were based on data from the military installations, which do not include breakdowns by type of use, such as air conditioning. Since present levels of air conditioning are generally much lower than the needs and can be expected to increase, air conditioning loads were based on the estimated amount required per square foot of floor space.

Table 3 gives the representative annual energy loads for a base with a 10 MW peak electric demand and the three types of climate. The thermal load is divided between space heating and other heat uses, principally hot water. The electric load shows the direct electric consumption and

Table 3

ANNUAL ENERGY LOADS FOR 10 MW BASES
(Millions of kWh)

	North Central	Southeast	Southwest
Space heating	279	141	94
Other heat uses	88	80	53
Total heat use	367	221	147
Electric			
Direct	63	60	59
Indirect*	183	176	174
Air conditioning			
Electric (indirect*)	7	35	62
Conventional absorption	15	76	134
Double-effect absorption	9	46	81
Total energy use (with electric air conditioning)	557	432	383
Recoverable waste heat			
Diesel	56	54	53
Gas turbine	131	126	125
Ratio of thermal to direct electrical (without air conditioning)	5.8	3.7	2.5

*10,000 Btu/kWh.

also the energy required to produce the electricity, based on the previously mentioned typical heat rate of 10,000 Btu/kWh for large central station fossil fuel power plants. The air conditioning load is given for three types of air conditioning. The indirect energy required (based on 10,000 Btu per kWh) is given for electric air conditioning. The actual

energy required is shown for both conventional absorption air conditioning and the more efficient double effect absorption air conditioning.

For comparison the amount of heat recoverable from the electric generation (excluding electricity for air conditioning) by multiple unit diesel or gas turbine TE plants is also given. The heat recoverable from the diesel TE system is small relative to the total energy load.

Table 3 includes the ratio of the thermal load to the electrical load. The thermal loads are much higher than the electrical loads.

Figure 4 shows in graphical form the same information as Table 3 for the Southeast type of climate.

Energy Load Profiles

The diurnal cycles of energy demands were needed for equipment sizing and fuel consumption calculations. Hour-by-hour energy loads were derived for five representative days of the year. The loads consist of the thermal, electric, and air conditioning loads. The five representative days are (1) high heating day, i.e., a cold mid-winter day, (2) a moderate heating day, (3) a day with no space heating (there is still a thermal load for other purposes) or air conditioning, i.e., a mild spring or fall day, (4) a moderate air conditioning day, and (5) a high air conditioning day, i.e., a hot mid-summer day. Each of the five days represents a certain number of days of the year, varying with the climate.

The complete energy load profiles for a 10 MW base are given in Appendix B. The loads for other base sizes are assumed to scale in proportion to the peak electric demand.

The loads for three of the days are illustrated in Figures 5 through 7 for a 10 MW base in the Southeast. The figures also show the recoverable heat from multiple unit diesel or gas turbine TE plants. For a high

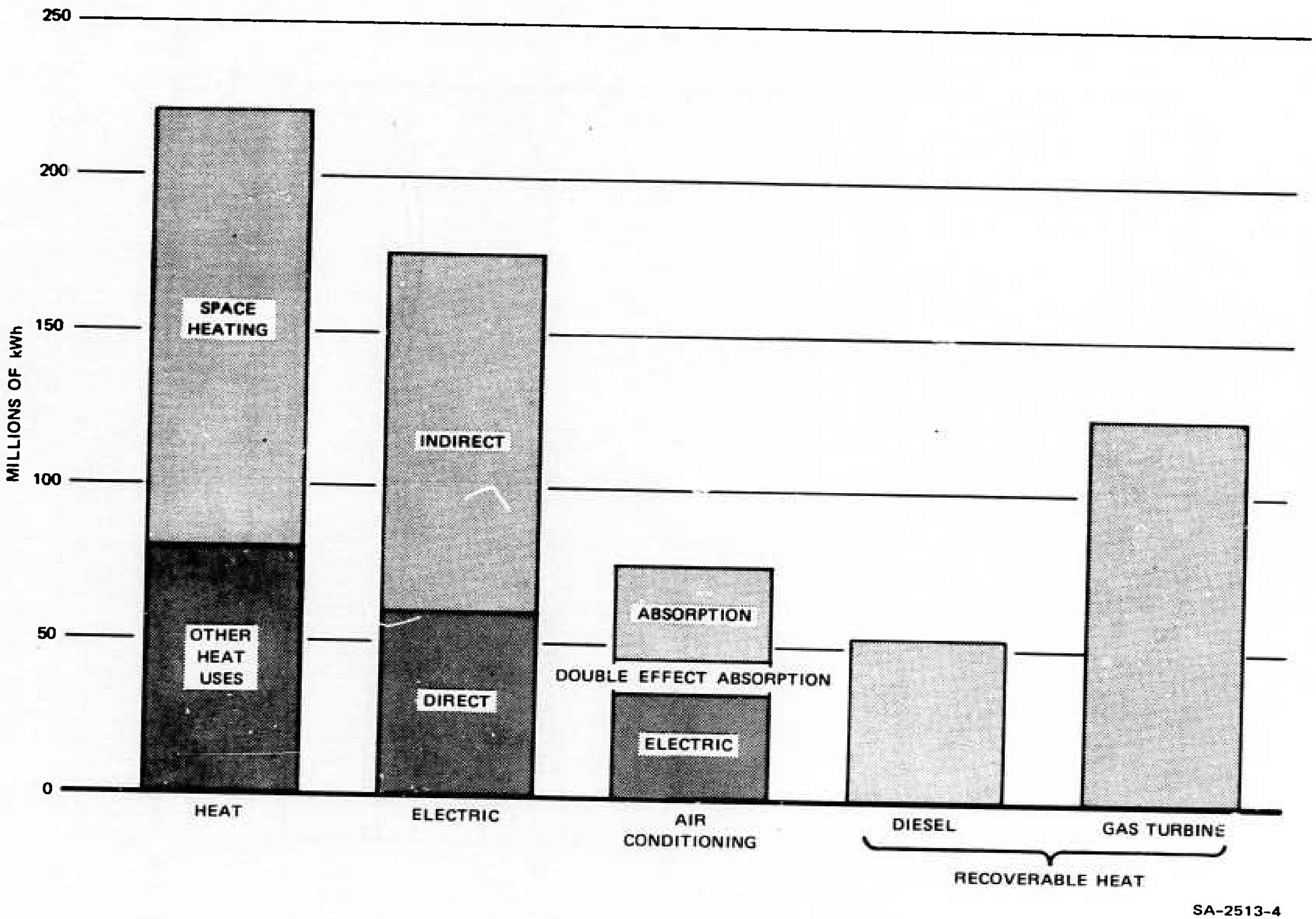


FIGURE 4 ANNUAL ENERGY LOADS—SOUTHEAST, 10 MW BASE

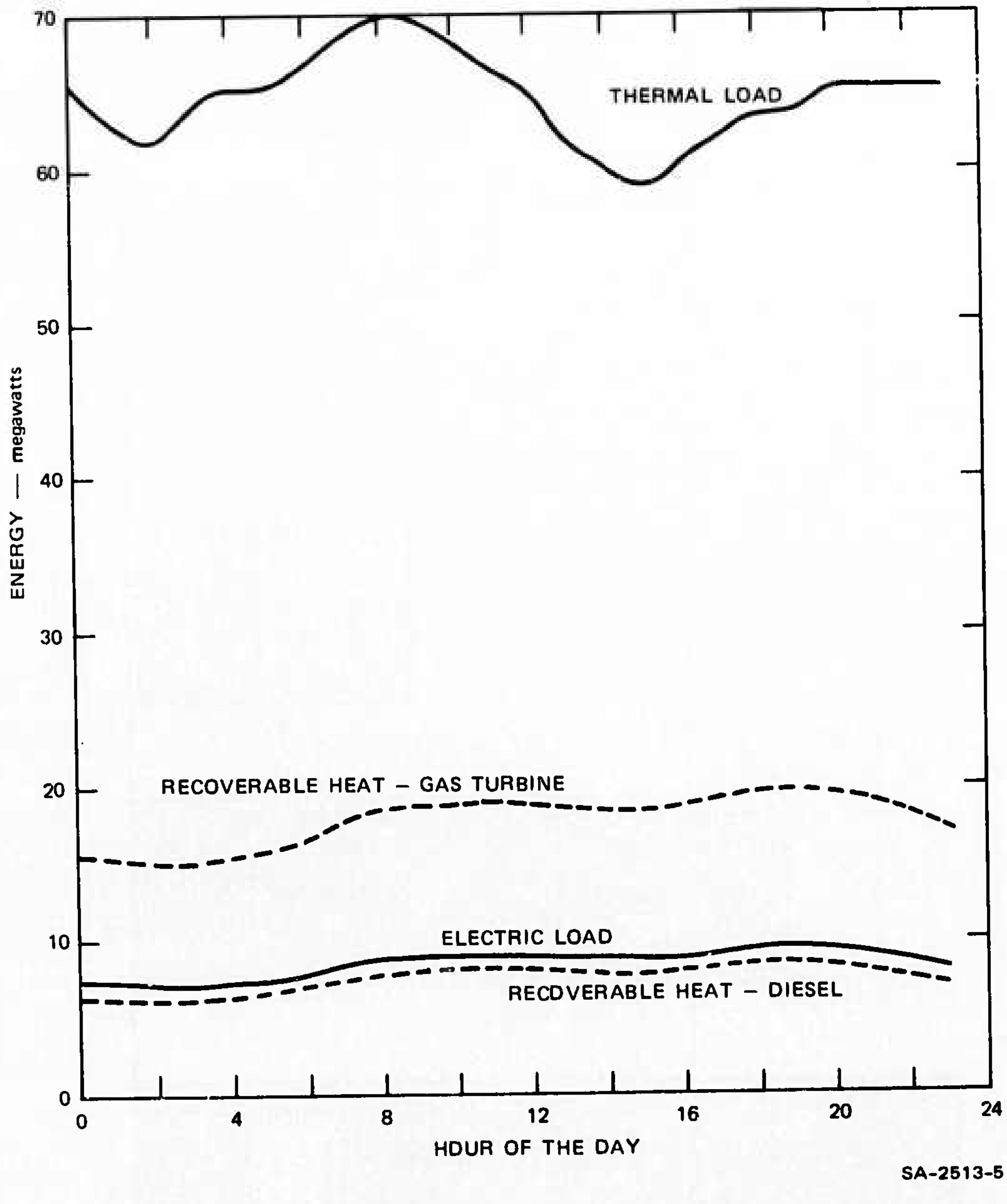


FIGURE 5 ENERGY LOAD PROFILES FOR HIGH HEATING DAY—SOUTHEAST, 10 MW BASE

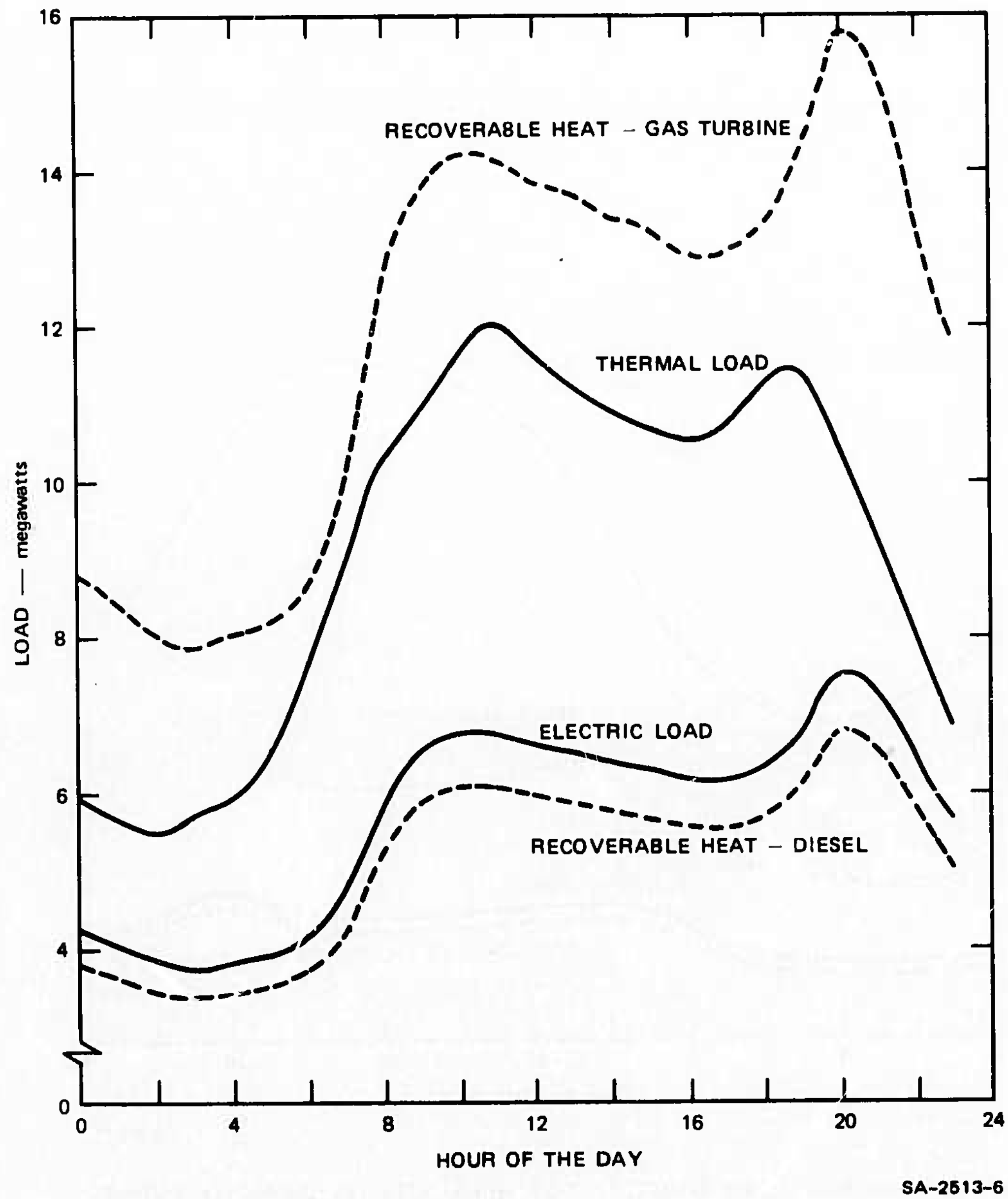


FIGURE 6 ENERGY LOAD PROFILES FOR NO SPACE HEATING OR COOLING DAY—SOUTHEAST, 10 MW BASE

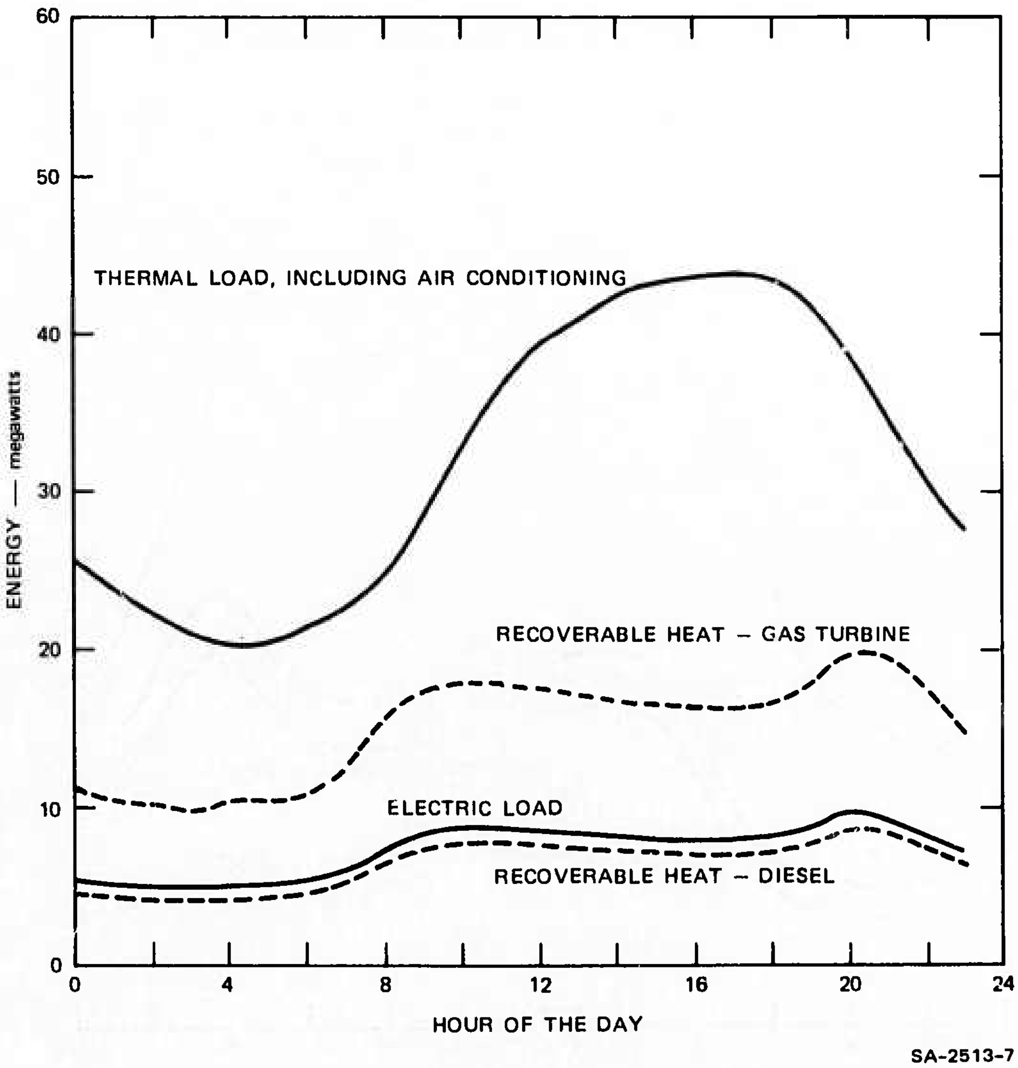


FIGURE 7 ENERGY LOAD PROFILES FOR HIGH COOLING DAY—SOUTHEAST, 10 MW BASE

heating day (Figure 5) the thermal load far exceeds the recoverable heat; hence, all of the recoverable heat can be utilized. For a no space heating or cooling day (Figure 6) the thermal load still exceeds the recoverable heat from the diesel system, but is less than the recoverable heat from a gas turbine system; in the later case not all of the recoverable heat could be utilized. For a high air conditioning day (Figure 7) the thermal load is increased because of the absorption air conditioning above the recoverable heat of the gas turbine.

IV FUEL SAVINGS FOR FOSSIL FUEL TE SYSTEMS

Fuel Efficiency

The fuel efficiency is defined as the electric energy consumed plus the useful heat output of the heating system, divided by the energy required to produce the electricity plus the heat value of the fuel required to meet the thermal load. The ratio of thermal to electric load ranges from about 10 in the colder climates in mid-winter, to 1 or 2 at times in the spring and fall.

As a function of the ratio of thermal to electric load, the efficiency of diesel and gas turbine multiple unit TE plants of 25 MW total capacity (unit capacities of 5 MW and 4.2 MW, respectively) are compared with that for a conventional system in Figure 8. A heat rate of 10,000 Btu per kWh was used for utility electricity in the conventional system, which gives a 34 percent efficiency for electric generation. An efficiency of 83 percent was used for the heating system in both the TE and conventional systems. Heat rates and heat recovery rates for both full load and 60 percent load were used for the TE systems.

The diesel system efficiency for electric generation only is nearly as high as that of the conventional system. Then, as the ratio of thermal to electric load goes from zero to about one, the diesel efficiency increases linearly as the recoverable heat is utilized for the thermal load. As the thermal load increases further, the additional thermal load is met by the auxiliary heating system with an 83 percent efficiency.

The gas turbine is much less efficient than the conventional system until the thermal to electric ratio reaches about 1.5, depending on the

Preceding page blank

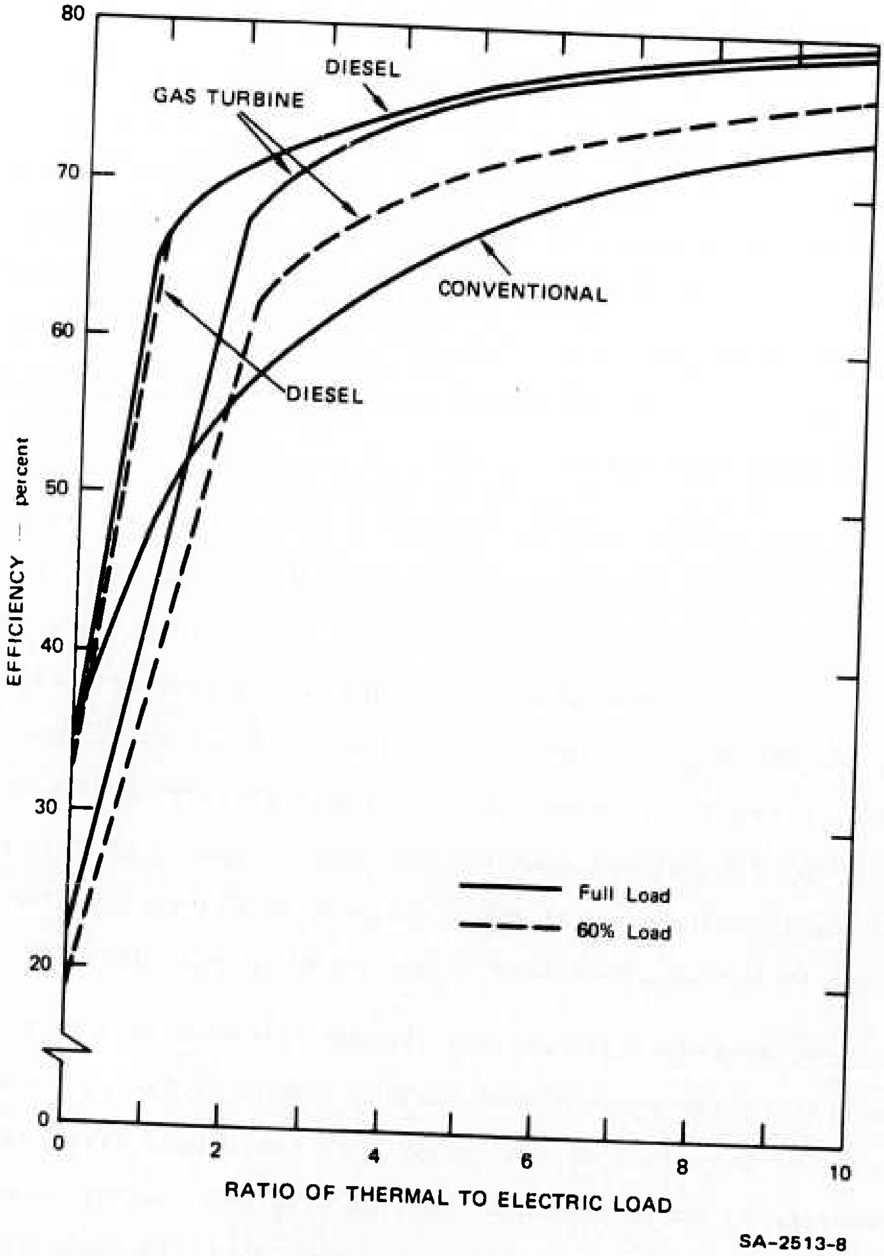


FIGURE 8 EFFICIENCY OF DIESEL AND GAS TURBINE MULTIPLE UNIT 25 MW TE PLANTS

part load condition. When the ratio reaches about 2, the recoverable heat is fully utilized. As the ratio increases further, the additional thermal load is met first by supplemental firing of the gas turbine, which has an efficiency of 90 percent, and then by the auxiliary heating system.

Compared with the diesel system, the gas turbine system efficiency at full load is nearly as high through most of the range of the thermal to electric load ratio. However, when the thermal to electric ratio is low, the gas turbine is much less efficient. Furthermore, the diesel efficiency is little affected by the part load condition, while the gas turbine efficiency drops off substantially when operating below rated load.

Figure 9 shows the efficiency of a 25 MW single unit gas turbine TE plant. In this case the efficiency is higher than that of a conventional system over the range of interest of the thermal to electric ratio. It is higher than that of the multiple unit gas turbine plant, and even higher than that of the diesel system over most of the range of the thermal to electric ratio.

The efficiency of a steam turbine TE plant is shown in Figure 10 for plant capacities of 25 MWe and 100 MWe. At the higher ratios of thermal to electric loads, the steam turbine efficiency is higher than that of the diesel or gas turbine systems. However, for the 25 MWe steam turbine, the efficiency is lower than that of conventional systems when the thermal to electric ratio is below 3. The efficiency of a 100 MWe steam turbine is very high, but that size is larger than needed by any present military installation.

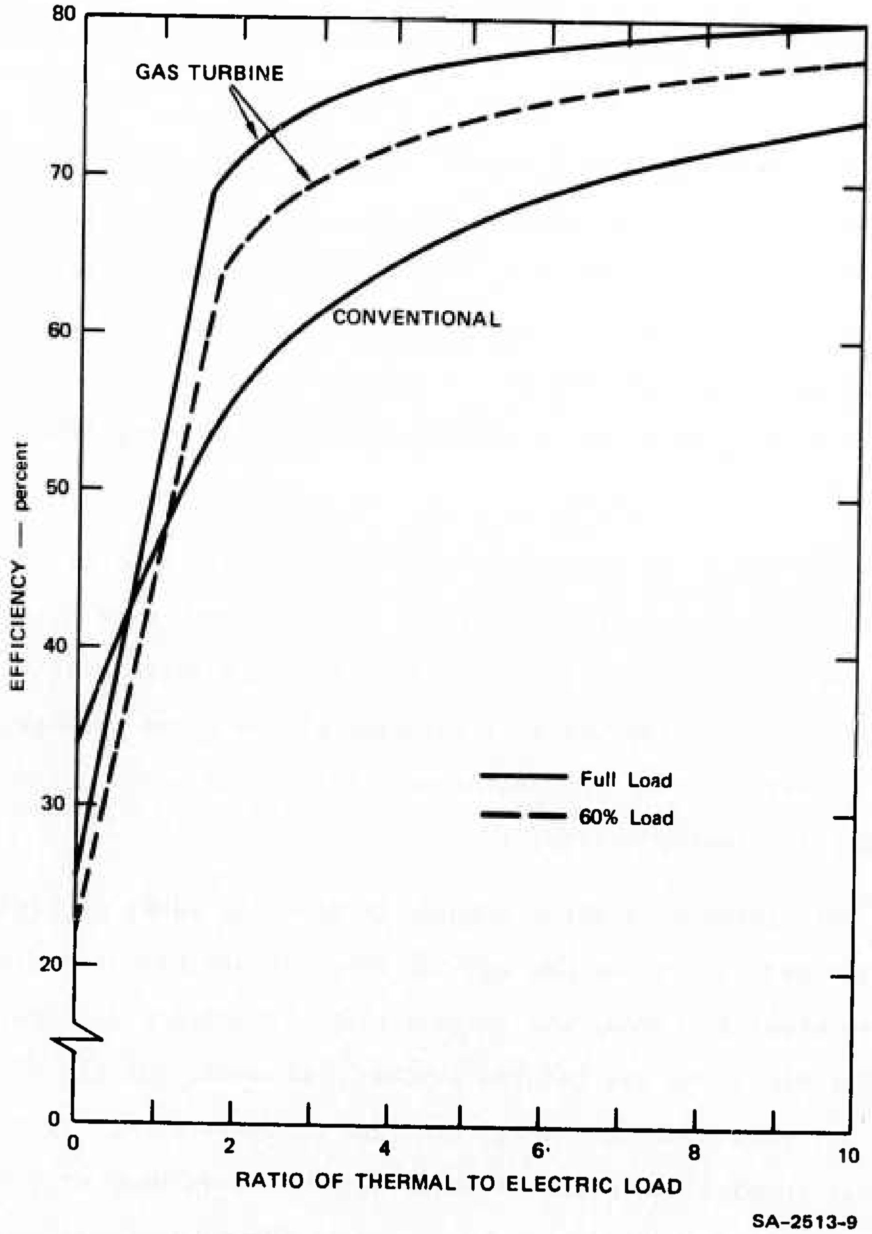


FIGURE 9 EFFICIENCY OF SINGLE UNIT 25 MW GAS TURBINE TE PLANT

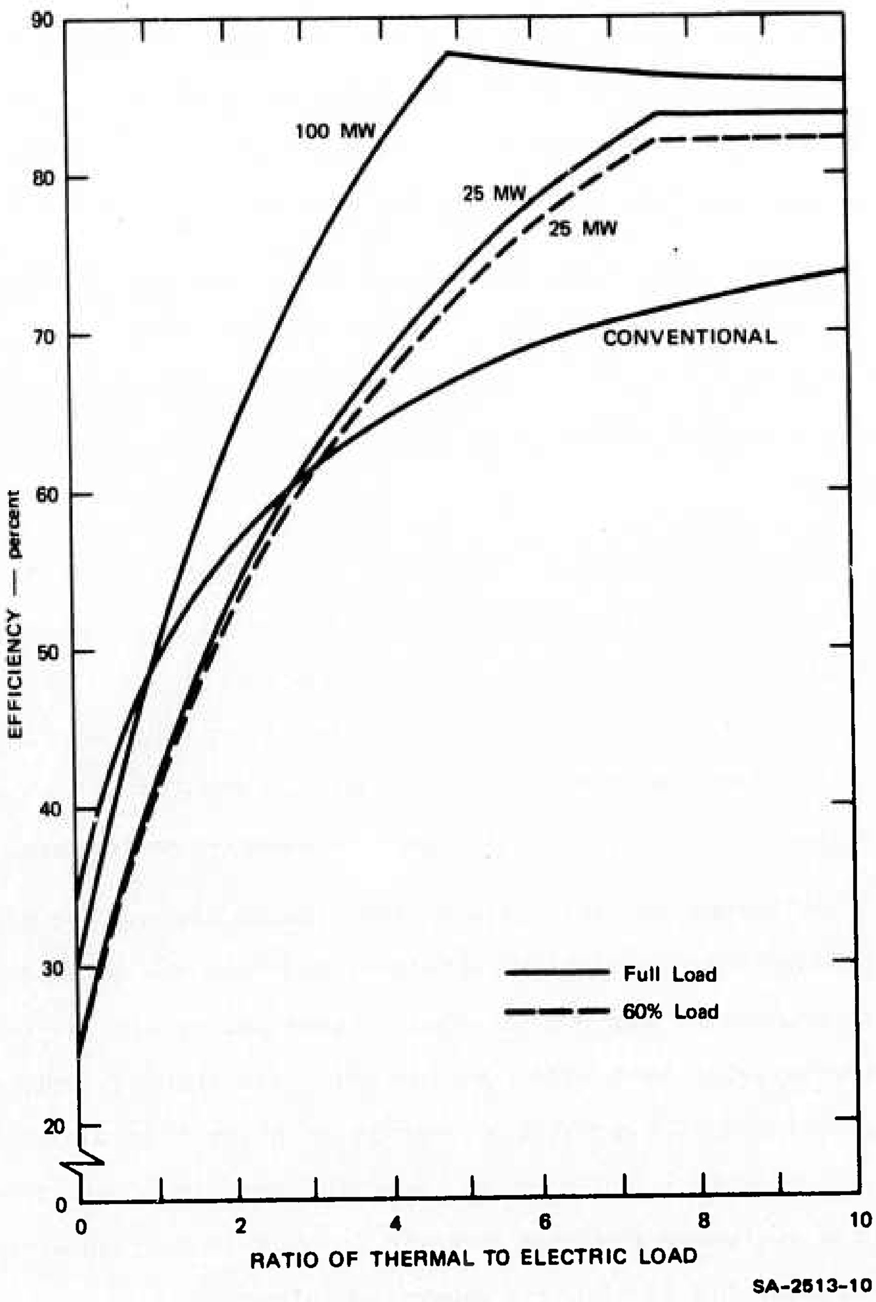


FIGURE 10 EFFICIENCY OF SINGLE UNIT STEAM TURBINE 25 MW AND 100 MW TE PLANTS

Multiple Unit Diesel and Gas Turbine

Fuel Consumption

The fuel consumption for both the TE and conventional systems consists of the fuel used for generating electricity plus the fuel used for auxiliary heating. A heat rate of 10,000 Btu per kWh for utility electricity in the conventional systems was assumed.

As indicated above, the system fuel efficiency varies with the ratio of thermal to electric load. Other factors affecting fuel consumption include the load on the electric generating units, the heat loss in the hot water transmission lines, and the mix of types of air conditioning.

Figure 11 shows the fuel consumption for a diesel TE system for bases of any size with the Southeast climate energy load pattern. Three air conditioning cases are shown, varying the amount and type of absorption air conditioning. The remainder of the air conditioning is the electrically driven compression type. Fuel consumption for a conventional system (using electric air conditioning) is also shown for comparison.

After allowance for the thermal loads (excluding air conditioning), the recoverable heat from the diesels provides heat for at most about 10 percent absorption air conditioning. Since absorption air conditioning is substantially less efficient in energy use than electric air conditioning, the use of a greater percentage of absorption air conditioning results in higher fuel consumption. However, the use of electric air conditioning increases the peak electric load, thus increasing the capital costs of the TE electric generating plant.

Figure 12 compares the fuel consumption for diesel and gas turbine TE systems with conventional systems in all three climates. The TE

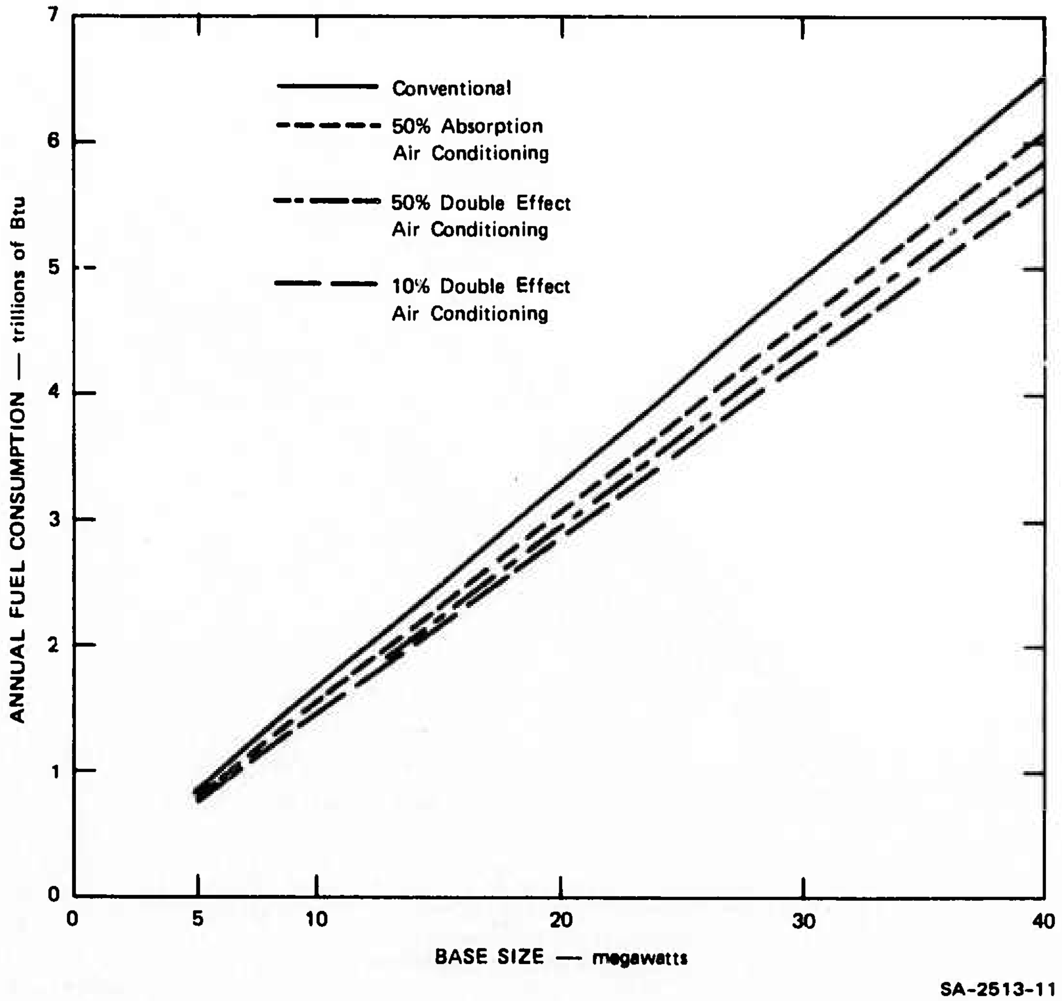


FIGURE 11 DIESEL FUEL CONSUMPTION—SOUTHEAST

cases assume 50 percent double effect absorption air conditioning. With the higher heat recovery from the gas turbines, the recoverable heat is sometimes sufficient for this level of absorption air conditioning. However, somewhat lower fuel consumption for the diesel could be obtained with a lower proportion of absorption air conditioning, as was shown in Figure 11.

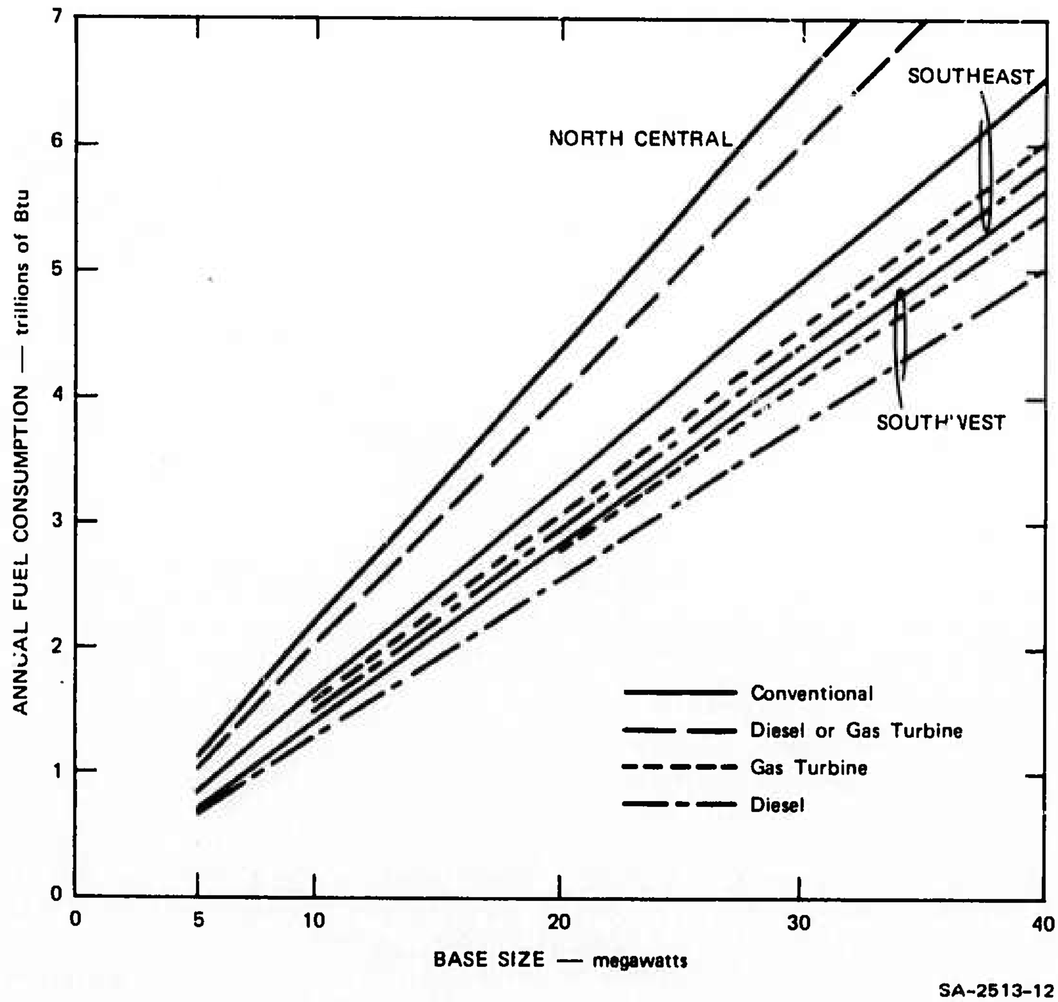


FIGURE 12 DIESEL AND GAS TURBINE FUEL CONSUMPTION

For the North Central climate the diesel and gas turbine fuel consumption are nearly the same, since the thermal to electric load ratio is mostly on the higher side of the range where the gas turbine fuel efficiency is comparable to that of the diesel (see Figure 8). In the Southeast, however, with lower thermal to electric load ratios, much of the recoverable heat from the gas turbine is wasted, and the fuel consumption is higher than in the diesel TE systems.

Fuel Savings

The fuel savings for the multiple unit diesel and gas turbine TE systems, compared with conventional systems, are given in Table 4. The fuel savings are expressed as a percent of the fuel used by the utility to generate the electricity consumed by the base plus the direct fuel consumption by the base with a conventional system. (An alternative definition that is sometimes used expresses the percent fuel savings relative to only the fuel used by the utility to produce the electricity. The percent fuel savings by that definition would be much higher than the figures in Table 4.) For comparability the air conditioning mix is the same for all cases--50 percent double effect absorption and 50 percent electric--except for the dispersed cases where 100 percent double effect absorption is used because two smaller size units in each complex would increase the cost per unit of capacity.

As the table shows, fuel savings tend to increase with size of base. The larger bases have slightly larger percent heat loss in the hot water lines but that is more than offset by the higher efficiency of the larger units. The dispersed cases provide smaller fuel savings, primarily because the electric generating units would be operating at lower load factors, where efficiency is lower. In the centralized plants, units would be shut down as the load dropped, thus giving higher unit load factors.

The centralized plant cases with heat transmitted to only part of the base also show reduced fuel savings, depending on how much of the recoverable heat is utilized. Because of the relatively low heat recovery of the diesel, most of the recoverable heat can be utilized if heat is transmitted to only about 25 percent of the base, depending on the minimum thermal load. This case is potentially important since it means that a TE plant could be added in a base expansion or modernization program without

Table 4

DIESEL AND GAS TURBINE* FUEL SAVINGS
COMPARED WITH CONVENTIONAL SYSTEM
(Percent)

	Base Size (MW)			
	5	10	20	40
Southeast				
Diesel	8.3%	8.7%	10.1%	10.5%
Gas turbine	5.0	5.0	6.5	8.2
Diesel dispersed	4.7	5.0	4.6	5.3
Gas turbine dispersed	2.0	2.3	2.0	2.6
Diesel-heat to 25% of base			7.0	
Gas turbine-heat to 50% of base			1.7	
North Central				
Diesel	6.9	7.7	8.4	8.7
Gas turbine	6.5	6.6	7.5	8.4
Southwest				
Diesel	8.4	9.6	10.6	11.2
Gas turbine	-1.4	-0.1	1.2	4.0

*With 50% double effect air conditioning for single plant cases and 100% for dispersed plants.

converting the entire base to utilization of the heat recovered from the electric generation. Because of the higher heat recovery from the gas turbine, adequate utilization of the waste heat would require most of the base to be connected by hot water lines to the central plant.

The type of energy load pattern affects the fuel savings in two opposite ways. With higher ratios of thermal to electric load (e.g., the North Central climate), the fuel savings are divided by a larger total fuel consumption, thus tending to reduce fuel savings expressed as a percent of

fuel consumption. On the other hand, the higher thermal loads permit greater utilization of the recoverable heat, thus increasing fuel savings. Since nearly all of the recoverable heat from the diesel can be utilized, the first effect predominates, and the percent fuel savings are lowest in the North Central, which has the highest thermal loads, and highest in the Southwest, which has the lowest thermal loads. For the gas turbine, the second effect predominates, and the percent fuel savings are highest in the North Central, and lowest in the Southwest.

Single Unit Gas Turbine

An alternative to the independent, multiple unit, TE system is a TE system with a single electric generating unit, dependent on a utility for supplying electricity during equipment downtime. The cases considered in this study involved a gas turbine sized larger than the electric load, operated to meet the thermal load, and with the excess electricity going into the utility network. To avoid the low efficiency of operating at low load factors, it was assumed that the gas turbine would be shut down when the thermal load dropped below 50 percent of capacity. The air conditioning was 100 percent double effect absorption.

Table 5 gives the fuel savings of a gas turbine system, compared with a conventional system, for various base sizes, gas turbine sizes, and the three climates. The fuel savings make allowance for the excess electricity going into the utility network, based on 10,000 Btu per kWh. The fuel savings are much higher than those for multiple unit TE plants for two reasons: first, the efficiency is higher for the larger generating units, as shown in Figures 9 and 10; second, more electricity is generated and hence there is more recoverable heat.

The fuel savings are higher where the thermal loads are higher, since the generating unit operates at higher load factors where the efficiency is greater. Also the system operates more of the time, since shutdown is

Table 5

SINGLE UNIT GAS TURBINE FUEL SAVINGS COMPARED WITH CONVENTIONAL SYSTEM

	Base Size (MW)	Turbine Size (MW)	Fuel Savings (percent)
Southeast	10	20	16.3%
	20	30	13.7
	20	40	16.6
	20	50	22.5
	40	80	20.5
North Central	20	40	20.7
Southwest	20	40	14.8

assumed when the load drops below 50 percent of capacity. For a given base size of 20 MW peak electric load in the Southeast, the table shows increasing fuel savings as turbine size increases from 30 to 50 MW. However, at some point of increasing turbine size, fuel savings would begin to drop off.

Steam Turbine

Single unit steam turbines were considered only for the larger bases since, as unit size decreases, fuel efficiency decreases and costs per unit of capacity increase sharply. The steam turbine TE cases use utility electricity to meet the downtime, but generate electricity only to meet the load of the military installation, with no excess electricity. The air conditioning was 100 percent double effect absorption.

Table 6 gives the percent fuel savings for bases of 25 and 40 MW peak electric load, and the three climates. Fuel savings are greatest for the larger bases in the coldest climates, and are negative for smaller bases in warmer climates.

Table 6

STEAM TURBINE FUEL SAVINGS
COMPARED WITH CONVENTIONAL SYSTEM

	Base Size (MW)	Fuel Savings (percent)
North Central	25	6.1%
	40	10.0
Southeast	25	-0.3
	40	5.4
Southwest	25	-6.3
	40	-0.4

Effect of Load Variations on Fuel Savings

The previous results for the three different climates provide some indication of the effect of variations in the energy load pattern on fuel saving. Some additional variations in the energy load pattern for a 20 MW base in the Southeast were also considered. The air conditioning loads for each climate were based on the estimated air conditioning requirements per square foot of floor space, since the data on electricity consumption did not permit identification of the part attributable to air conditioning, and since current levels of air conditioning are substantially below desired levels. The effect of lower levels of air conditioning on fuel savings for a multiple unit gas turbine TE system is shown in Table 7. If the air conditioning load is half that of the standard case previously assumed (the standard case is described in Appendix B), the reduced utilization of recoverable heat is offset by the reduction in total energy load so that the percent fuel saving is almost unchanged. With no air conditioning, the percent fuel saving is reduced. Because of the lower heat recovery from the diesel, these effects would be reversed, i.e., reductions in the air conditioning load would increase the percent fuel savings.

Table 7

EFFECT OF AIR CONDITIONING AND HEAT LOAD VARIATIONS ON FUEL SAVINGS

(Southeast, 20 MW Base, Gas Turbine TE System)

	Fuel Savings (percent)
Standard air conditioning load	6.5%
One-half air conditioning load	6.4
No air conditioning	4.3
One-half air conditioning and one-half heat load	6.0

Another case is shown in Table 7 where both the air conditioning and the heat loads are reduced by half. The percent fuel savings for the gas turbine is reduced slightly, but again the percent fuel savings for the diesel would be increased.

V COSTS OF FOSSIL FUEL SYSTEMS

The primary purpose of the cost analysis in this study was to indicate the conditions under which the TE systems would have favorable costs. As previously noted, the uniform annual costs shown are the sum of the annualized capital costs, the annual operating and maintenance costs (excluding fuel), and the uniform annual costs of the fuel and, for conventional systems, electricity. As shown later, the major factor and major uncertainty in comparison of costs of TE with conventional systems is the relative costs of fuel and electricity over the operational life of the systems.

Capital Costs

The capital costs of the TE systems are made up of the installed costs of each of the four main elements: (1) electric generating plant, (2) high temperature water generator, (3) hot water lines, and (4) air conditioning chillers. The breakdown of costs into these four items is illustrated in Figure 13 for the case of a 10 MW base in the Southeast, with centralized, multiple unit diesel or gas turbine TE system. The gas turbine costs are lower than those of the diesel, partly because of the lower cost of the electric generating plant but more so because the higher heat recovery from the gas turbine permits a smaller hot water generator. The hot water lines represent a major cost, though that cost will vary with the length of lines required. For this case there were three lines serving six complexes, with a total of 4.5 miles of line. The air conditioning cost is based on a mix of 50 percent double effect absorption and 50 percent electric.

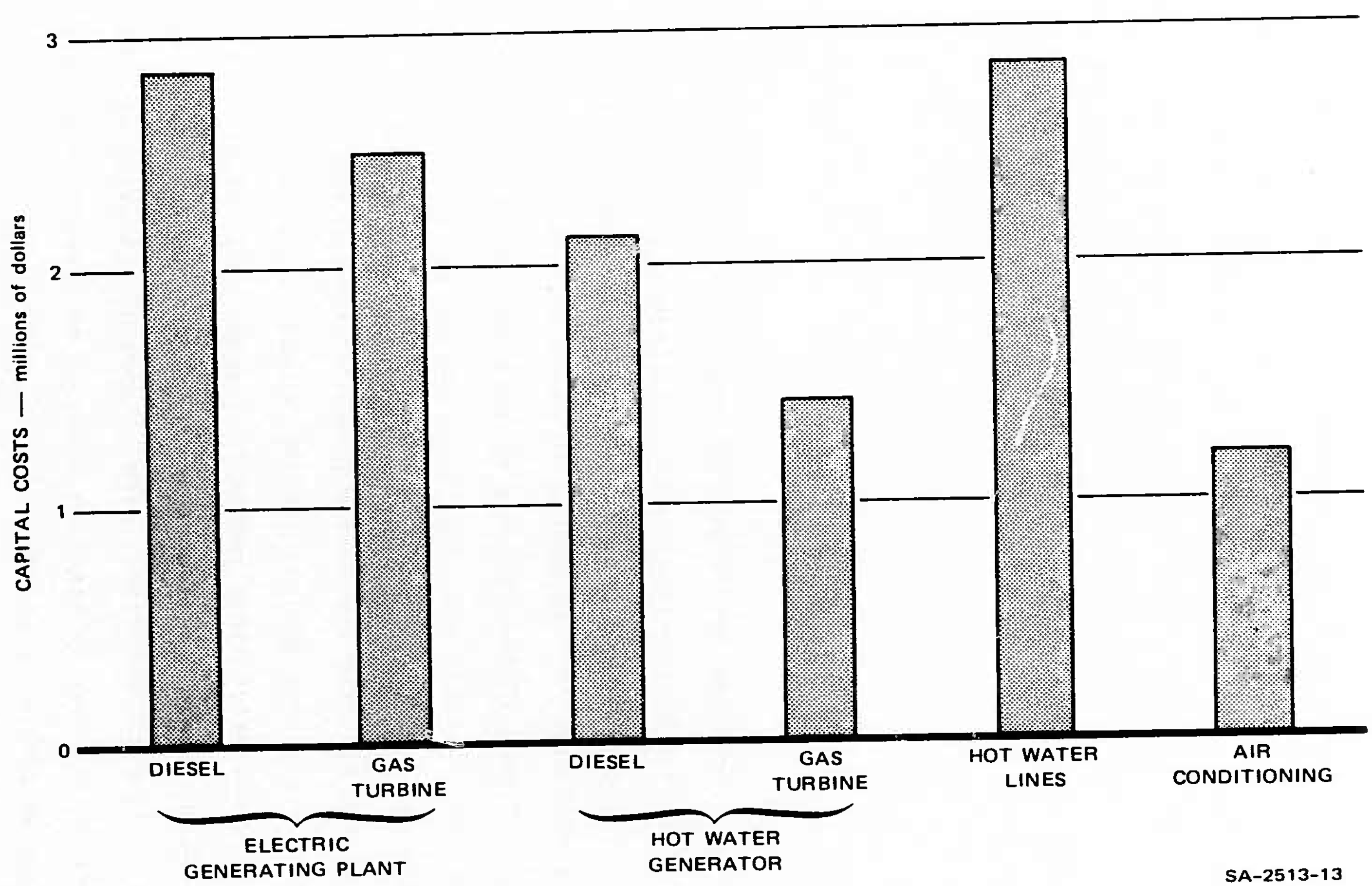


FIGURE 13 CAPITAL COSTS OF SYSTEM ELEMENTS FOR DIESEL AND GAS TURBINE—SOUTHEAST, 10 MW BASE

The total capital costs for bases of any size in the Southeast, for multiple unit diesel and gas turbine TE systems, and for conventional systems, are shown in Figure 14. The TE systems include the mix of 50 percent electric and 50 percent double absorption air conditioning, while the conventional system has all electric. The costs of the conventional system consist of the hot water generators and the air conditioning; since the hot water generators in the conventional system are located in each complex rather than a centralized plant, the costs per unit of capacity are higher than those of the TE systems. Also, greater capacity is required because the heat recovery from the electric generation meets part of the heat needs in the TE systems. For these reasons the capital costs of the conventional systems are more than half as much as those of the TE systems.

Uniform Annual Cost Excluding Fuel

As already noted, the uniform annual cost excluding fuel consists of the annualized capital costs plus the annual operating and maintenance costs. Figure 15 shows this cost for different base sizes in the Southeast, for centralized, multiple unit, diesel and gas turbine TE systems, a diesel TE system with dispersed generating units, and conventional systems. Also shown, for a 20 MW base, are the annual costs of diesel and gas turbine TE systems with heat transmission to only 25 percent and 50 percent, respectively, of the base. Again, the air conditioning for the TE systems is a mix of 50 percent double absorption and 50 percent electric, and for the conventional systems, all electric. The annual costs for the conventional systems exclude the costs of electricity as well as fuel.

The dispersed diesel case shows little advantage in costs over the centralized plant case for the smaller bases, but the cost advantage increases with size of base. For the smaller bases, the increased costs of the hot water generators for the dispersed case offsets the elimination

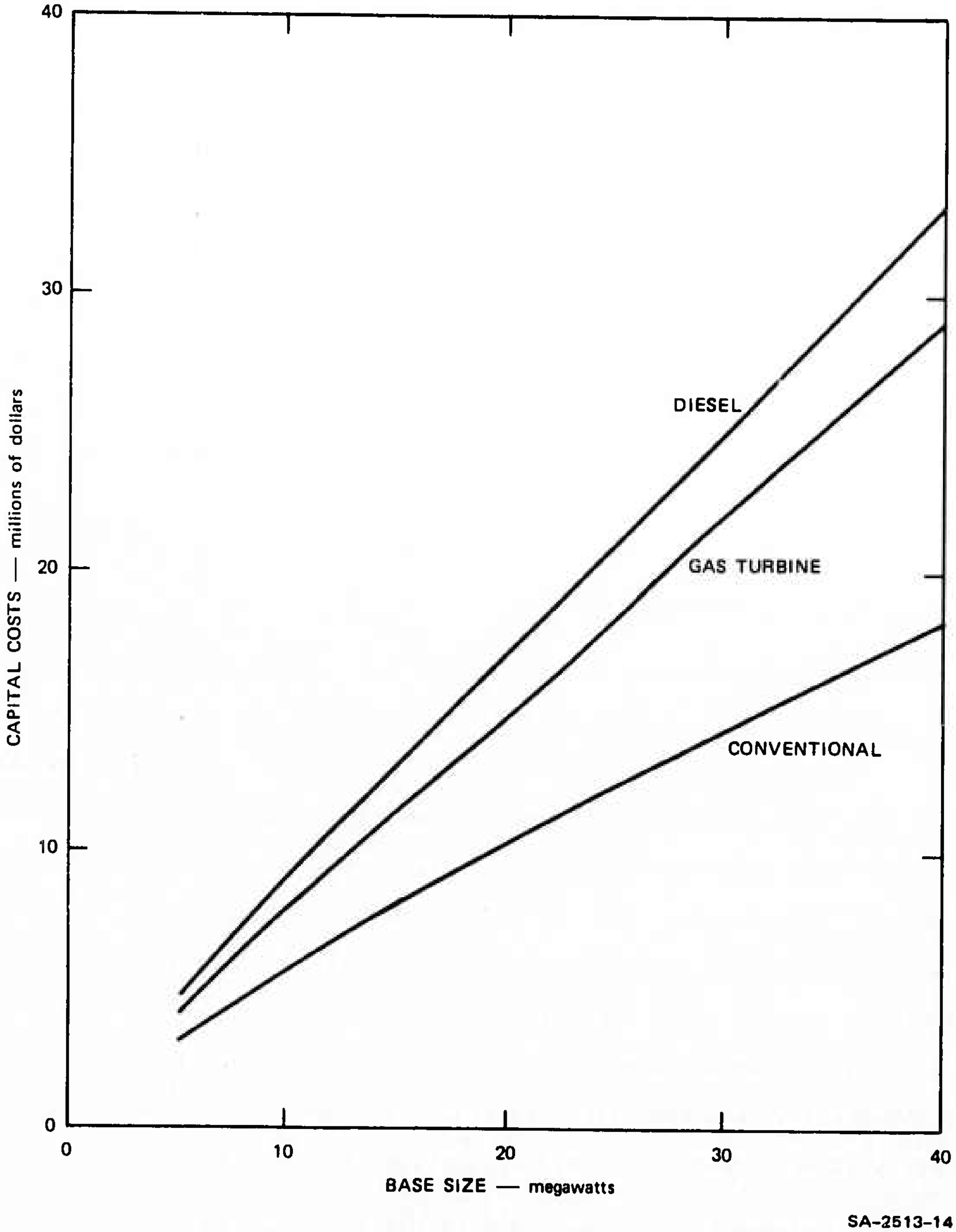


FIGURE 14 CAPITAL COSTS VERSUS BASE SIZE FOR DIESEL, GAS TURBINE, AND CONVENTIONAL SYSTEMS—SOUTHEAST

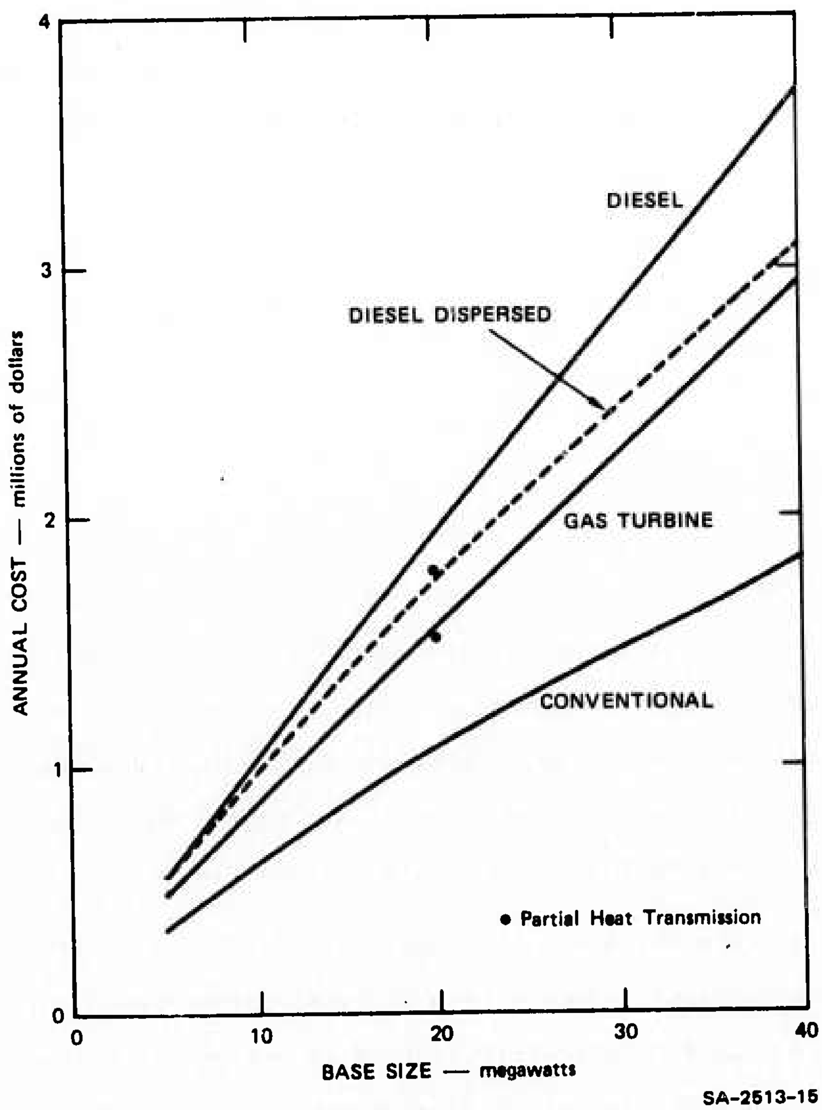


FIGURE 15 ANNUAL COST (EXCLUDING FUEL) FOR DIESEL, GAS TURBINE, AND CONVENTIONAL SYSTEMS—SOUTHEAST

of hot water line costs. For the same reason, the cost reduction for the case of heat transmission to only part of the base is also small. The costs of the dispersed or part-base cases for the gas turbine are approximately the same as those of the centralized plant, complete base case.

Figure 16 compares the annual costs of centralized, multiple unit, diesel and gas turbine TE systems with conventional systems for the North Central and Southwest energy load patterns.

Figure 17 shows the annual cost for the steam turbine (oil fired) for the three climates, and the annual cost for the single unit gas turbine cases for the Southeast.

Fuel and Electricity Costs

Total uniform annual costs have to include the cost of fuel and, in the case of conventional systems, the cost of electricity as well. There are substantial variations now in the costs of fuel and electricity. These costs have been increasing rapidly over the last few years and substantial further increases are expected. Future energy costs are highly uncertain. Therefore, for total uniform annual costs and cost comparisons, the costs of fuel and electricity have been treated parametrically.

Fuel costs (the uniform annual costs of the fuel over the 25-year system life) were taken to range from $1 to $3 per million Btu; $1 per million Btu is approximately equivalent to $6 per barrel of fuel oil, which is close to its present price. Regulated natural gas prices to large consumers are often lower but that situation is not expected to continue. Coal prices are generally lower than the $1 per million Btu, but coal is not applicable to the diesel or gas turbine TE systems.

The electricity charges to military installations consist of a demand charge based on peak electric demand, and an energy charge based on electricity consumed. Although the actual formulas are complicated, the

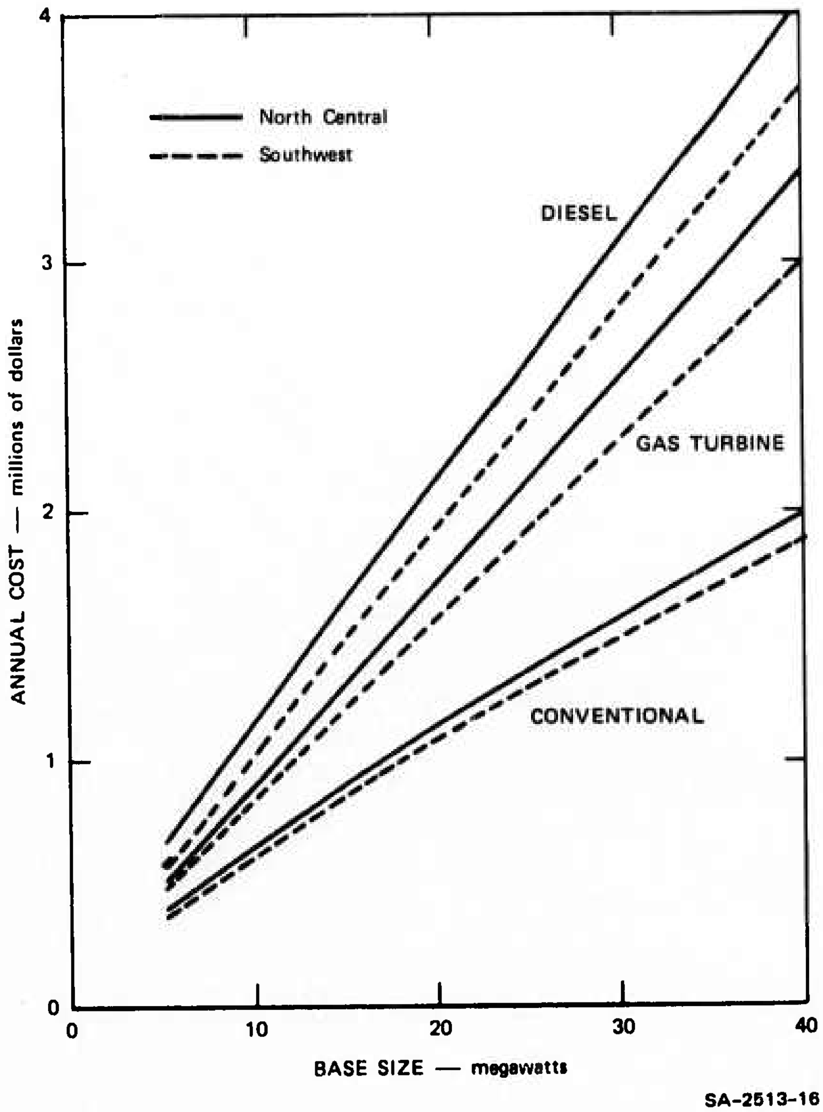


FIGURE 16 ANNUAL COST (EXCLUDING FUEL) FOR DIESEL, GAS TURBINE, AND CONVENTIONAL SYSTEMS—NORTH CENTRAL AND SOUTHWEST

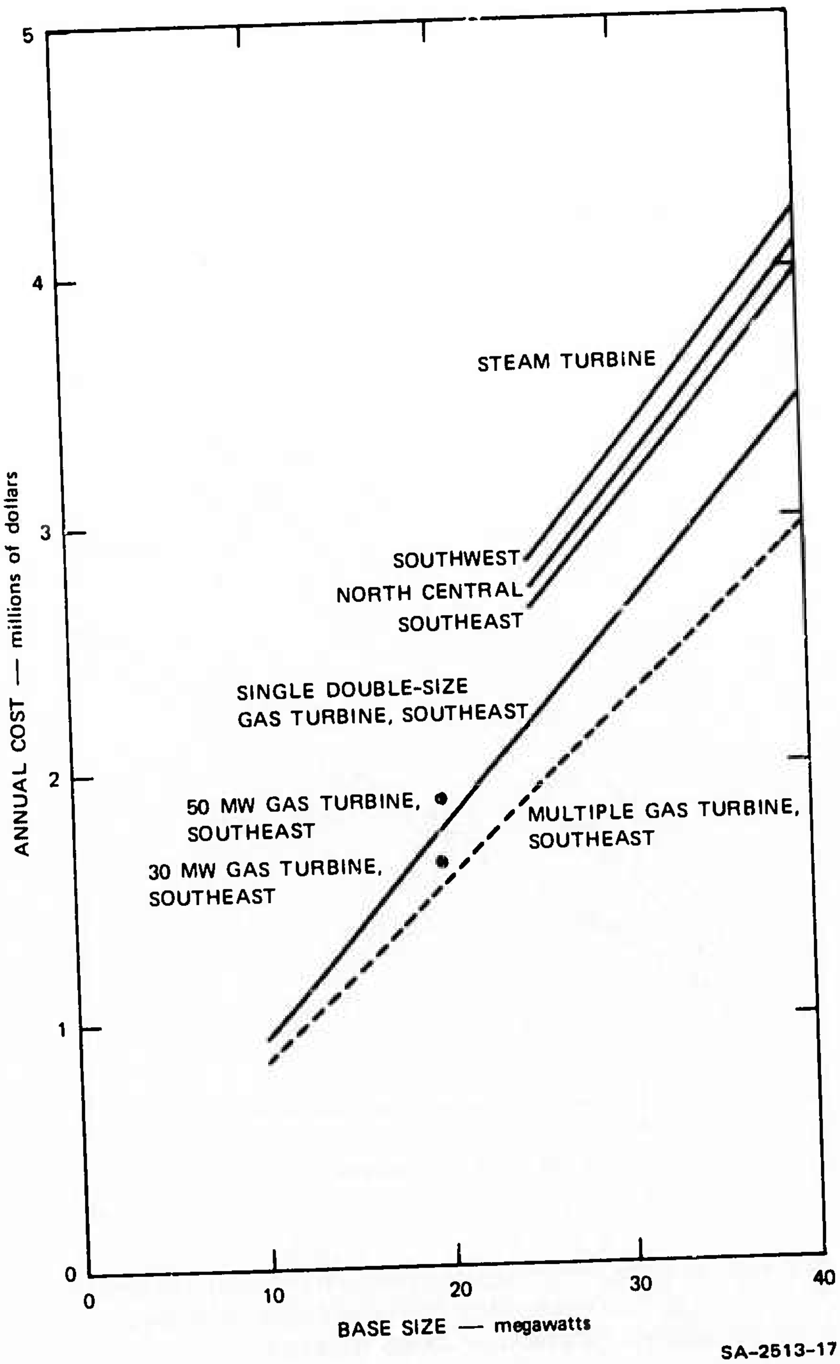


FIGURE 17 ANNUAL COST (EXCLUDING FUEL) FOR STEAM TURBINE AND GAS TURBINE SYSTEMS

current charge is typically about $12,000 per MW of peak demand and 0.75¢ per kWh for the energy charge. The energy charge, though not expressed in this way, consists of a fixed amount plus a variable amount based on the cost of the fuel used to produce the electricity: at present, typically, the fixed charge is 0.4¢ per kWh and the fuel charge is 0.35¢ per kWh, the latter being equivalent to 0.35¢ per million Btu for fuel, based on a heat rate of 10,000 Btu per kWh.

The demand charges, which are related to utility capacity requirements, have been treated as constant in this study since costs are shown in constant 1973 dollars. The demand charge was assumed to be $15,000 per MW of peak demand, except that $12,000 per MW was used in the cases of a 0.75¢ per kWh energy charge.

For fossil fuel utility plants, the energy charge should increase by the amount of increase in the price of the fuel used to produce the electricity. However, fuel costs to the utility may be lower than the costs of gas or oil for a TE system, since the utility may be able to use cheaper oil or coal. Since coal is less scarce than oil, and also can be supplied entirely from domestic sources, coal prices may not increase as rapidly as oil prices. An increasing proportion of electricity will be coming from nuclear power. Although the costs of nuclear fuel are also expected to increase, the fuel costs are a much smaller part of costs in nuclear plants than in fossil fuel plants.

For comparison with the costs of TE systems, the costs of the conventional systems were plotted as a function of the costs of the fuel used for heating. The electric energy charge was treated in two ways. One way was to consider it as independent of the cost of the fuel for heating but still to treat it as a parameter, with discrete values ranging from 0.75¢ to 2.5¢ per kWh. The other way was to vary the electric energy charge with the cost of fuel for heating. The energy charge was assumed to consist of 0.5¢ per kWh plus the cost of the fuel for generating the electricity, based on a heat rate of 10,000 Btu per kWh. In one case

the cost of the fuel to the utility for generating electricity was taken to to be the same as the cost of fuel to the base for heating. In another case the fuel for electricity generation was taken to cost half as much as the fuel for heating.

The effect of these different assumptions about electric energy charge on the uniform annual cost of conventional systems is illustrated in Figure 18, for a 10 MW base in the Southeast. As the figure indicates, the annual cost varies widely with the different electric energy charges.

Comparison of Costs Between Centralized Multiple Unit TE Systems and Conventional Systems

A comparison of the total uniform annual costs of centralized multiple unit diesel and gas turbine TE systems and conventional systems is shown in Figure 19 for a 10 MW base in the Southeast. The total annual costs are plotted as a function of the uniform annual costs of fuel. For the conventional system, the cost is given for three fixed values of the electric energy charge. The electric demand charge is included in the total cost but not in the electric energy charge. For example, if fuel costs are $1 per million Btu while electricity costs are 0.75¢ per kWh, the TE costs are higher than the costs of the conventional system.

Figure 20 shows the same comparison as Figure 19, but with the energy charge for the conventional system varying with fuel cost. If the electric utility pays the same price for fuel as the military base pays, the TE system costs are lower than those of conventional systems. However, if, for example, the base is paying $2 per million Btu for oil while the utility is paying $1 per million Btu for coal, then the conventional system has lower costs.

Figure 19 showed the fuel cost points at which the costs of the conventional system crossed the costs of the TE systems. For a given electric energy charge, the conventional system would cost more than

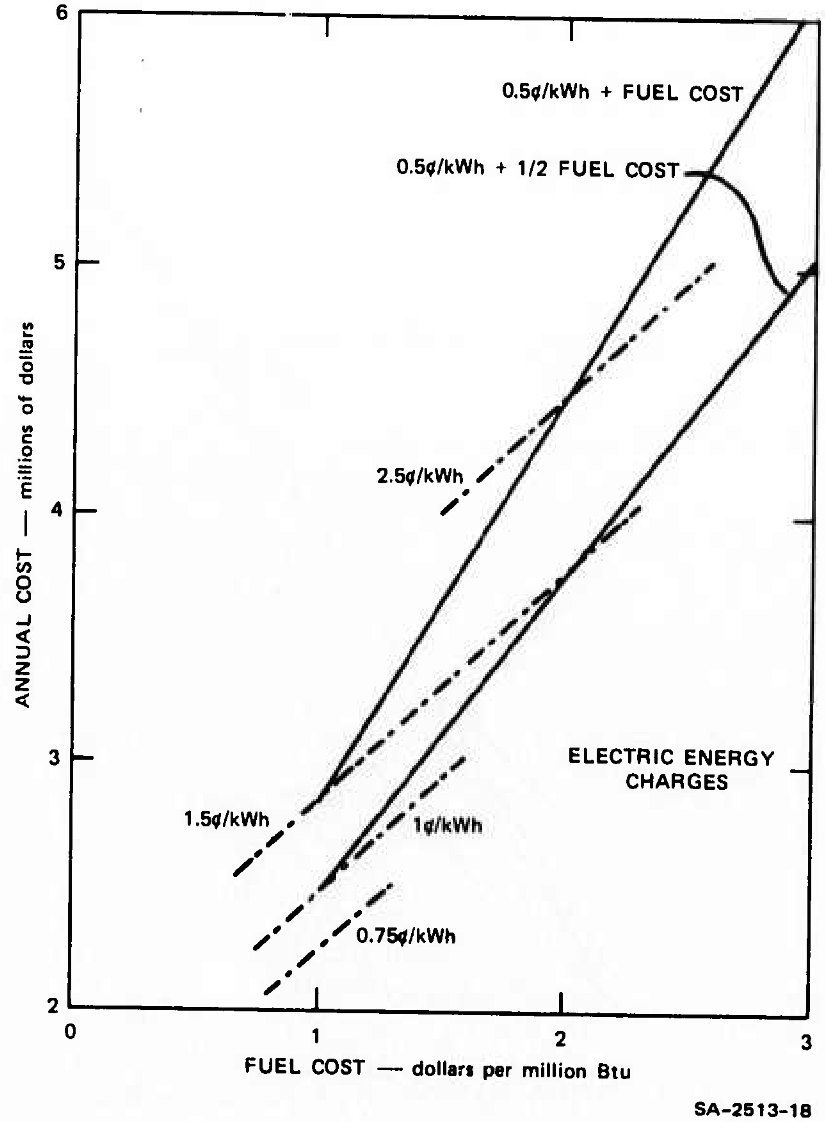


FIGURE 18 ANNUAL COST VERSUS FUEL COST OF CONVENTIONAL SYSTEM WITH VARIATIONS IN ELECTRIC ENERGY CHARGES—SOUTHEAST, 10 MW BASE

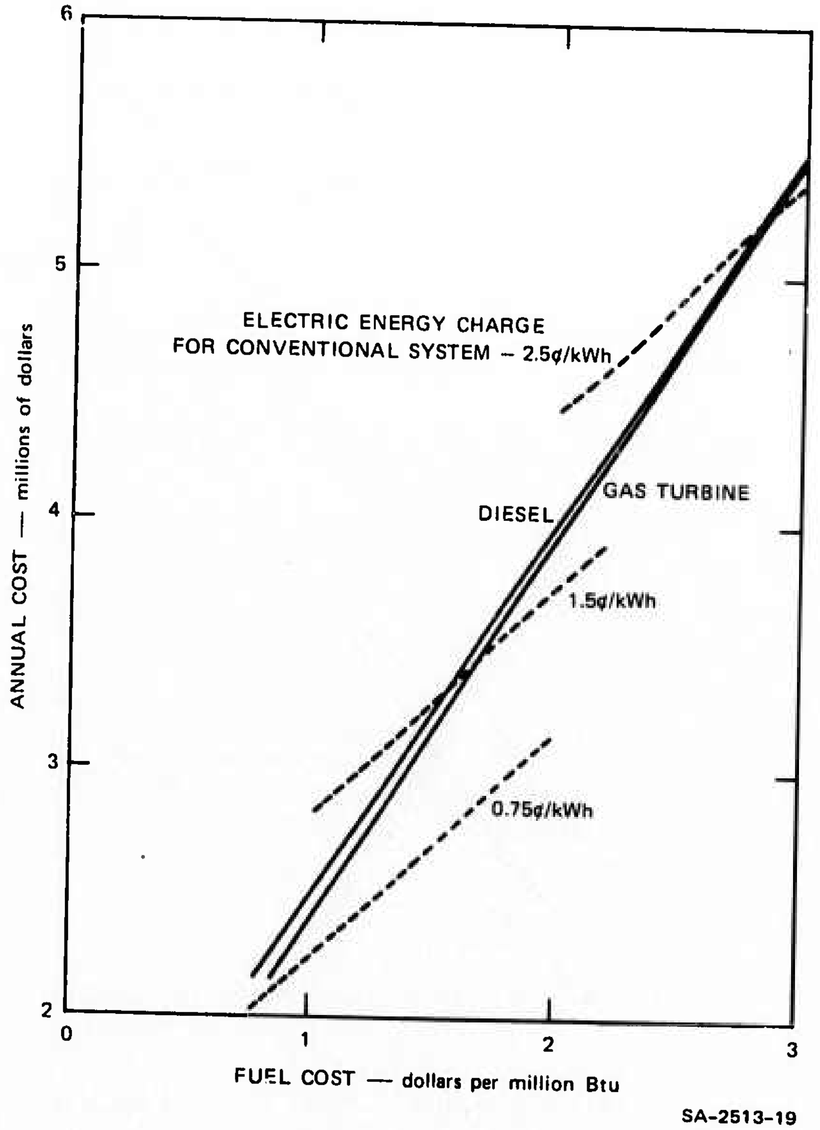


FIGURE 19 ANNUAL COST VERSUS FUEL COST OF DIESEL AND GAS TURBINE TE SYSTEMS AND CONVENTIONAL SYSTEM—SOUTHEAST, 10 MW BASE

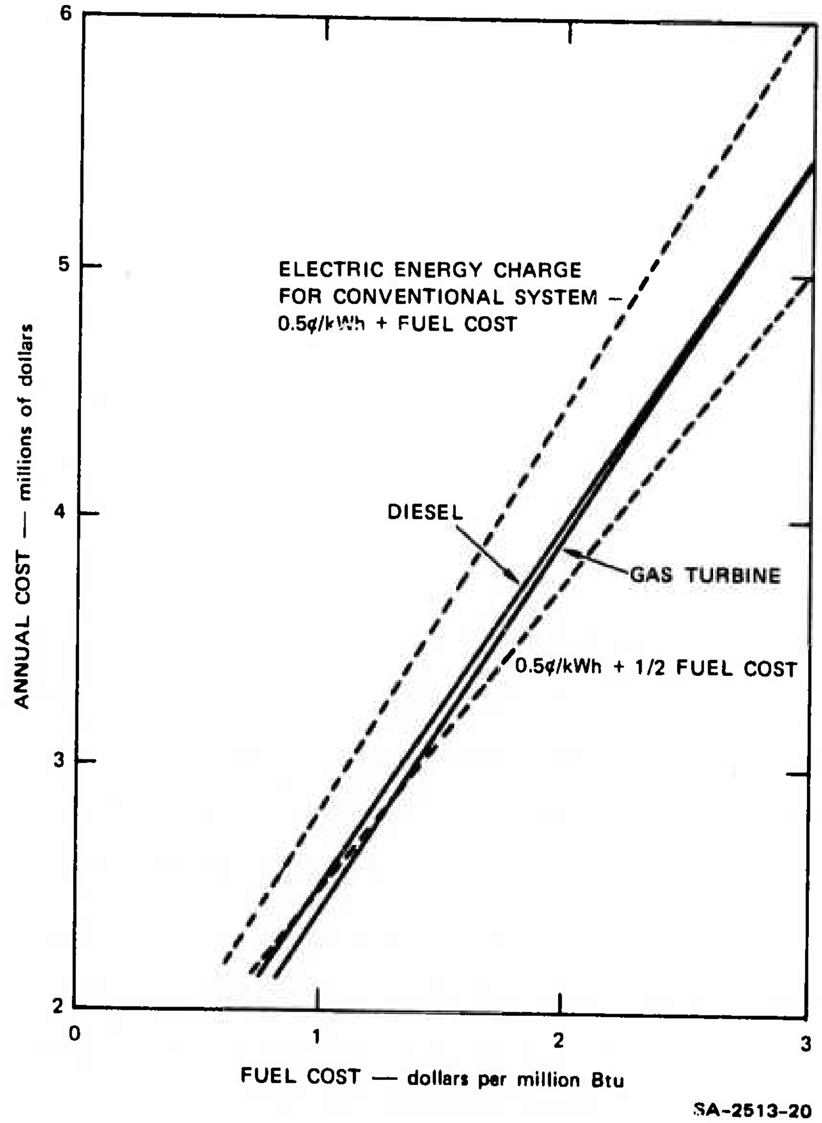


FIGURE 20 ANNUAL COST VERSUS FUEL COST OF DIESEL AND GAS TURBINE TE SYSTEMS AND CONVENTIONAL SYSTEM, ELECTRIC ENERGY CHARGE VARYING WITH FUEL COST—SOUTHEAST, 10 MW BASE

the TE system if the fuel cost were less than the crossing point, and would cost less than the TE system if the fuel cost were higher.

Figures 21 through 24 show the uniform annual cost of diesel TE systems and the break-even fuel cost points, for the other base sizes and climates. Only the centralized, multiple unit, diesel system with 50 percent double effect air conditioning is shown, since the cost difference between the diesel and gas turbine, and among the different air conditioning mixes is small relative to the variation in cost of a conventional system for different electric energy charges. With given estimates of the uniform annual price of fuel and electricity over the operational life of the systems, these figures provide an indication of whether the cost of a TE system would be higher or lower than the cost of a conventional system.

Effect of Electric Energy Charge on Cost Comparisons

The cost comparison between TE systems and a conventional system is primarily dependent on the relative changes in fuel and electricity prices over the system lifetimes. Because of its importance, this relationship is illustrated in three different ways in Figures 25 through 27

Figure 25 shows the total uniform annual costs of a diesel TE system and a conventional system as a function of the price increase factor for the electric energy charge, and of three price increase factors for fuel. The starting point, i.e., price increase factor of 1, is assumed to be \$1 per million Btu for fuel and 1¢ per kWh for the electric energy charge. If the fuel price increase factor is two, and the electric price increase factor is also two, the TE system cost is lower than that of the conventional system. If, however, the electric price increase factor is only 1.5, then the cost of the conventional system is lower. The general conclusion is that unless the electric energy charge increases nearly as much as the fuel price, the TE costs will be higher.

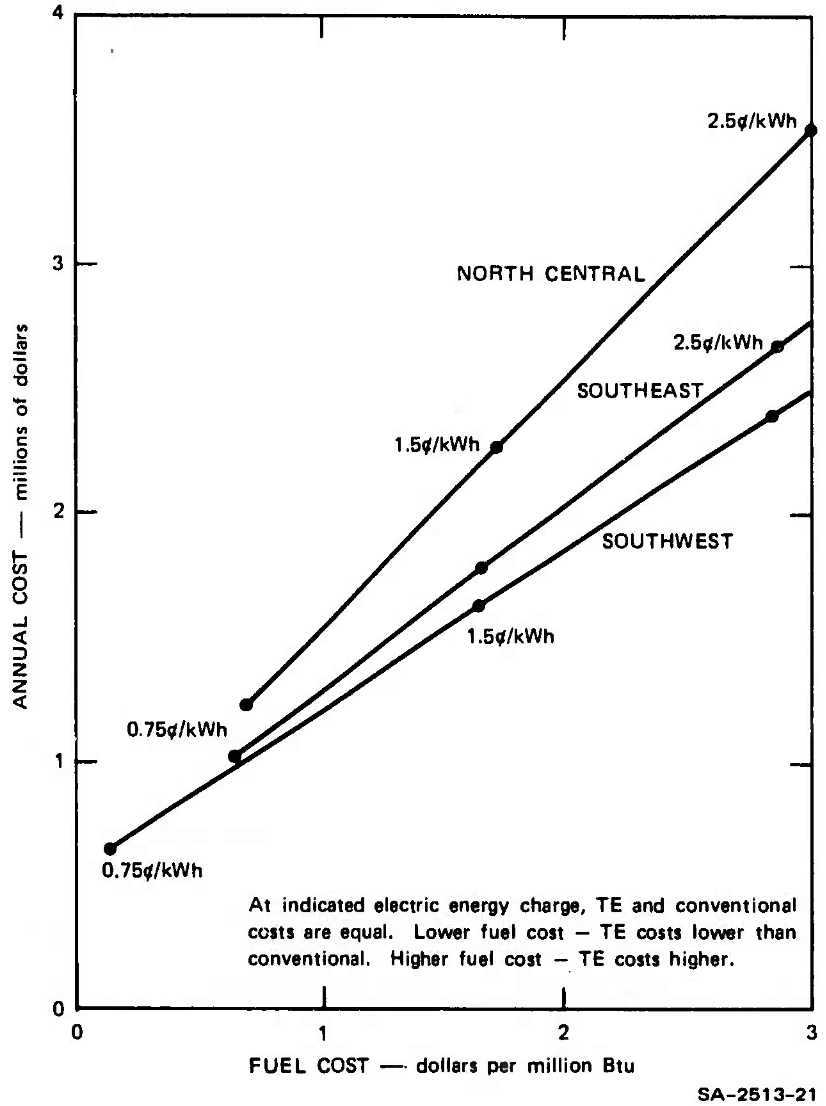


FIGURE 21 ANNUAL COST VERSUS FUEL COST OF DIESEL TE SYSTEM COMPARED WITH CONVENTIONAL SYSTEM— 5 MW BASE

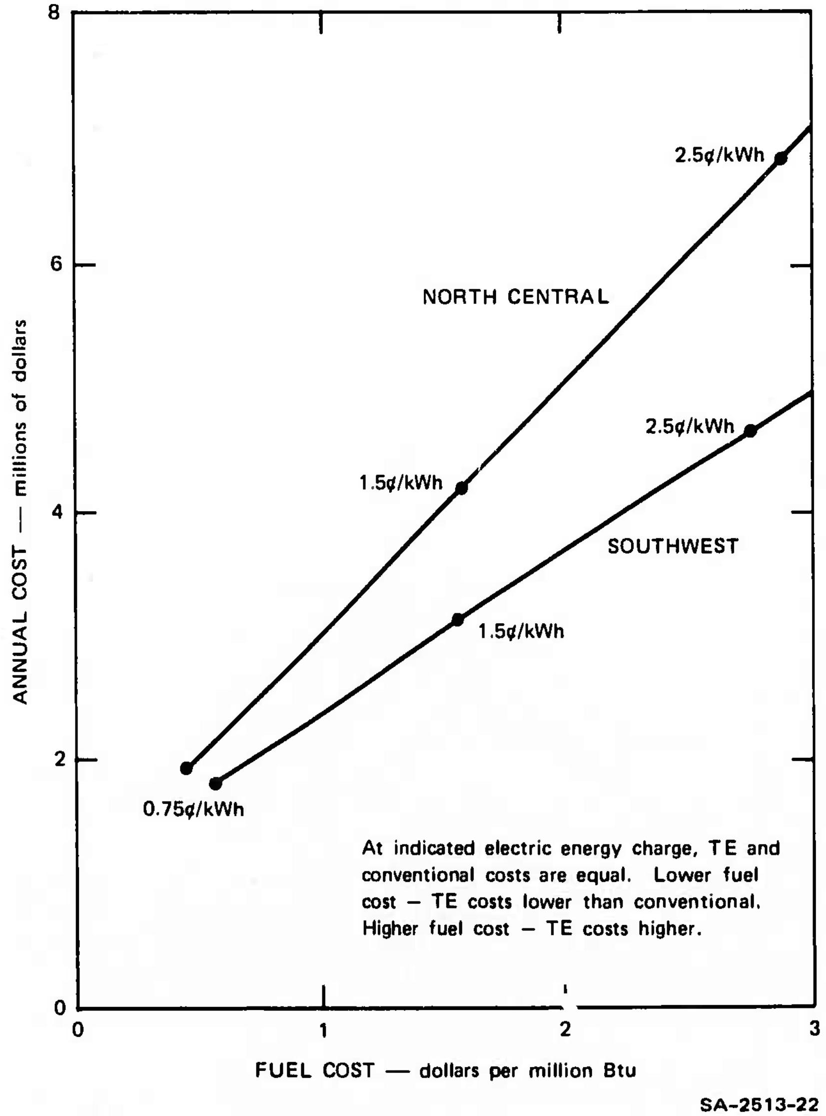


FIGURE 22 ANNUAL COST VERSUS FUEL COST OF DIESEL TE SYSTEM COMPARED WITH CONVENTIONAL SYSTEM—10 MW BASE

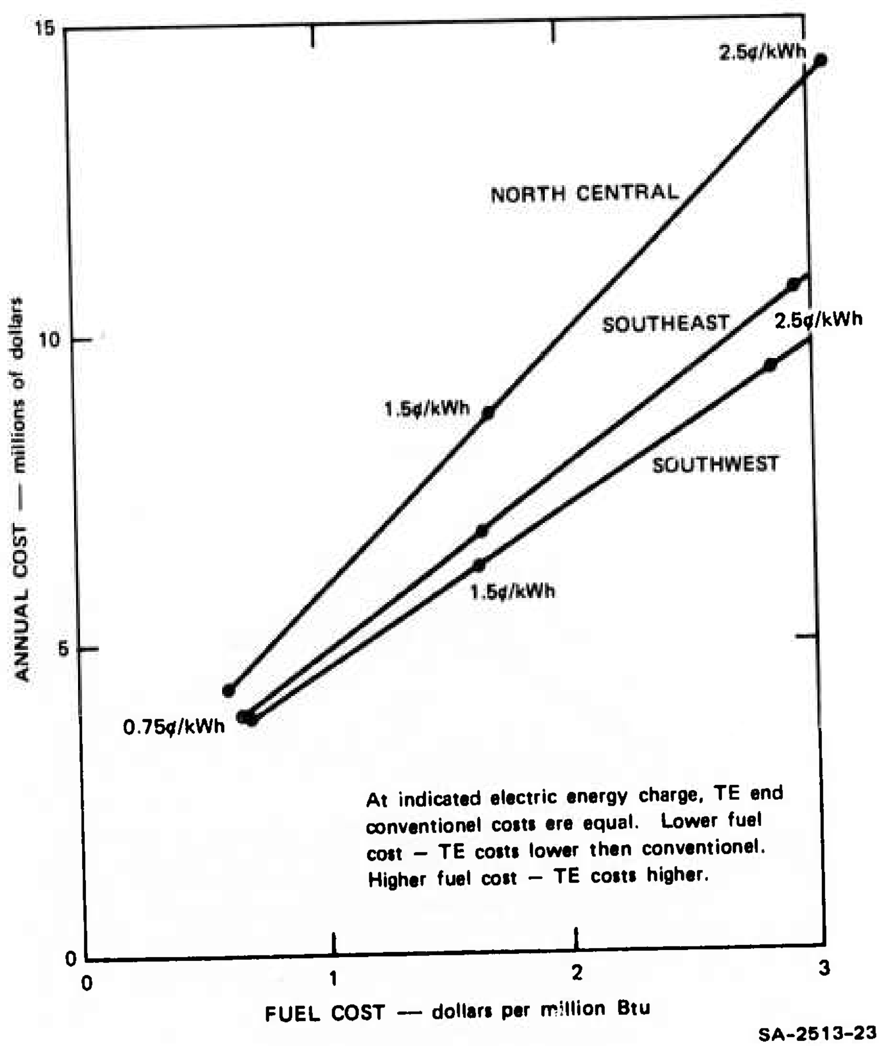


FIGURE 23 ANNUAL COST VERSUS FUEL COST OF DIESEL TE SYSTEM COMPARED WITH CONVENTIONAL SYSTEM—20 MW BASE

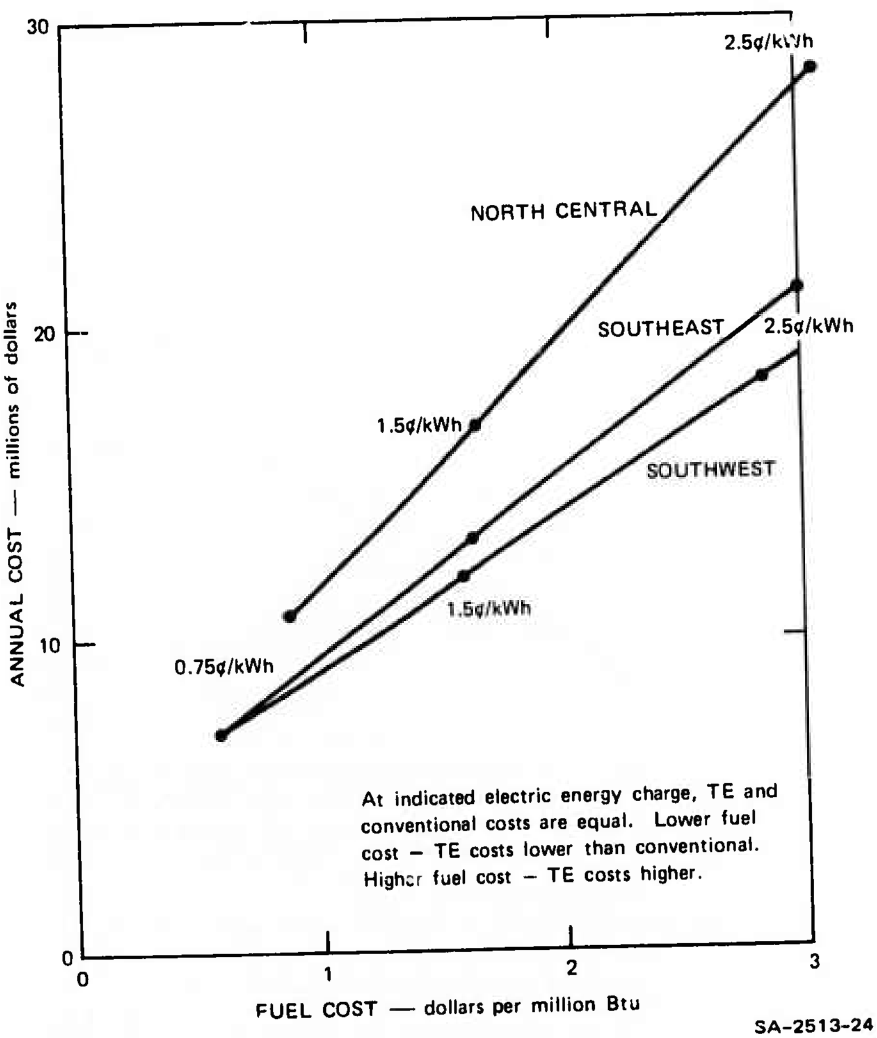


FIGURE 24 ANNUAL COST VERSUS FUEL COST OF DIESEL TE SYSTEM COMPARED WITH CONVENTIONAL SYSTEM—40 MW BASE

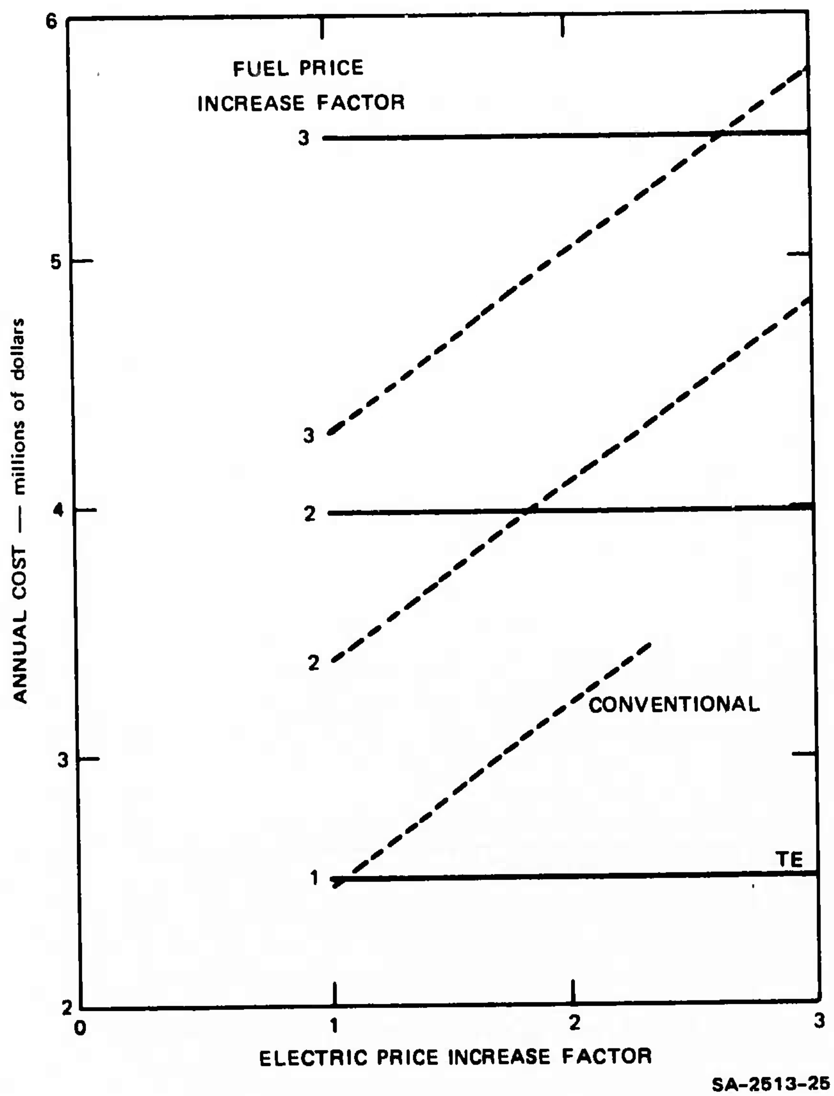


FIGURE 25 ANNUAL COST OF DIESEL TE AND CONVENTIONAL SYSTEMS FOR VARIOUS ELECTRIC PRICE INCREASE FACTORS—SOUTHEAST, 10 MW BASE

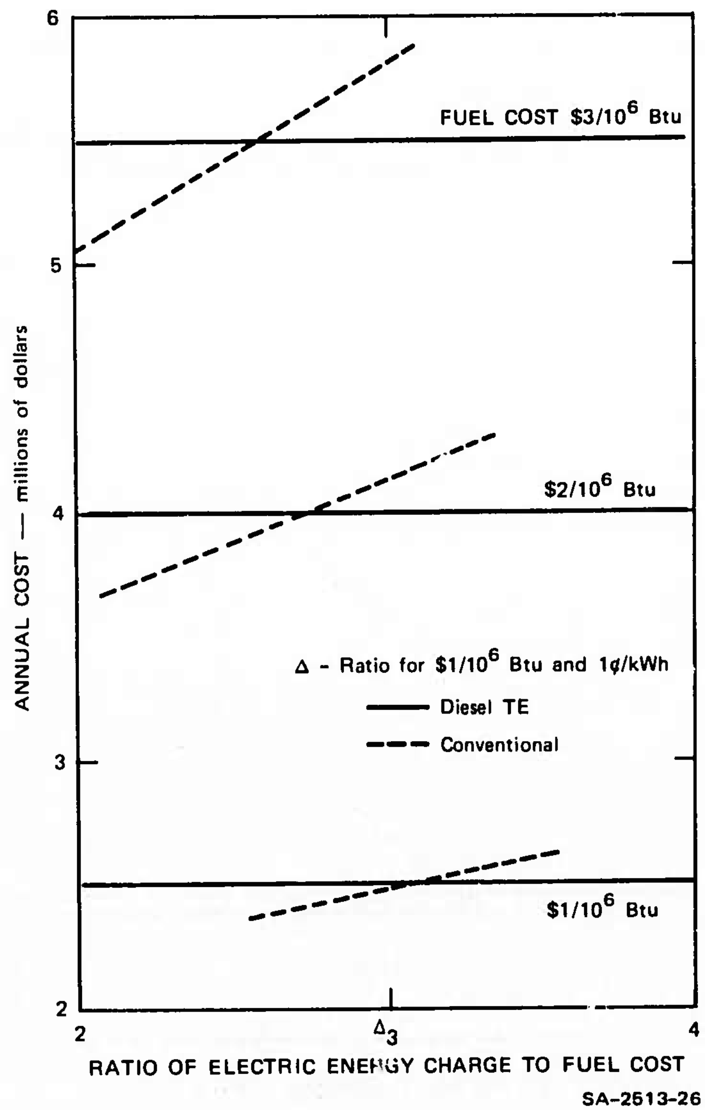


FIGURE 26 ANNUAL COST OF DIESEL TE AND CONVENTIONAL SYSTEMS VERSUS RATIO OF ELECTRIC ENERGY CHARGE TO FUEL COST—SOUTHEAST, 10 MW BASE

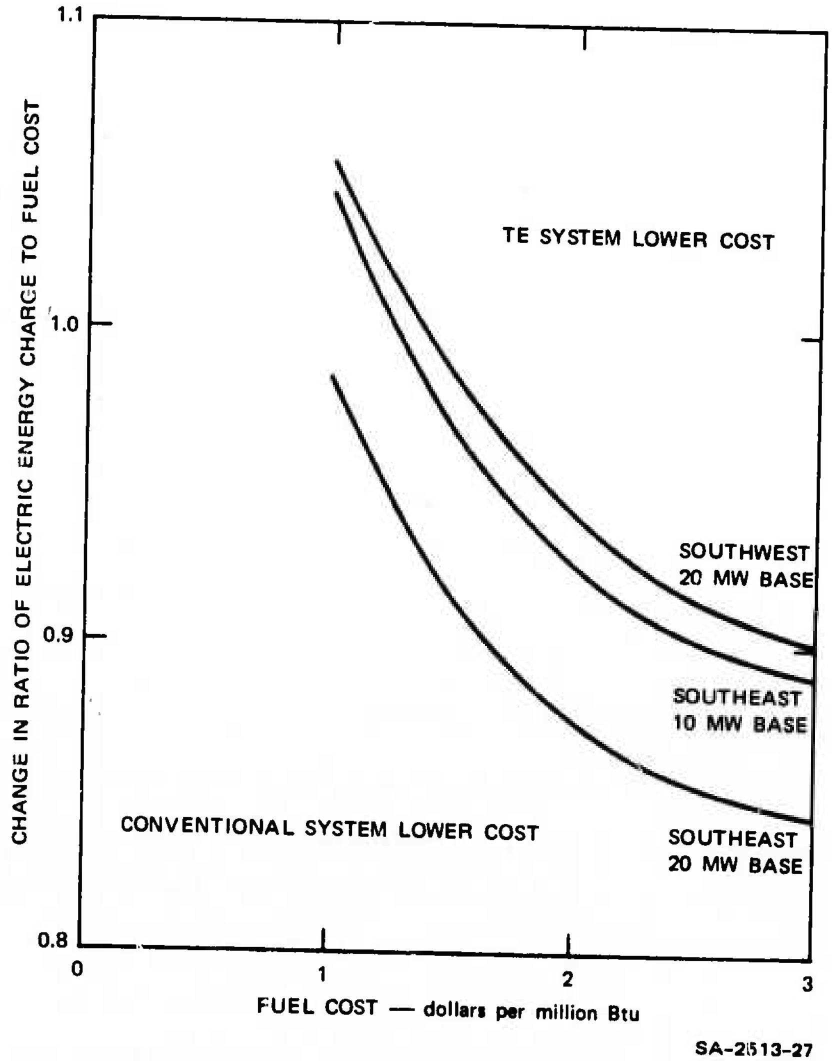


FIGURE 27 COMPARISON OF DIESEL TE AND CONVENTIONAL SYSTEM COST IN RELATION TO CHANGE IN RATIO OF ELECTRIC ENERGY CHARGE TO FUEL COST

The same conclusion is illustrated in another way in Figure 26, which shows the costs of TE and conventional systems as a function of the ratio of electric energy charge to fuel cost. At 1¢ per kWh and $1 per million Btu, this ratio is 2.93. As fuel costs increase the break-even point of this ratio, for equal TE and conventional costs, drops slightly.

Figure 27 shows the change in the ratio of the electric energy charge to the fuel cost, for equal TE and conventional system costs, as a function of fuel costs. For a 10 MW base in the Southeast, if fuel costs are $2 per million Btu and the ratio of electric energy charge to fuel costs is changed by a factor of 0.93, the TE and conventional costs are equal. If the change in that ratio is higher, or if the fuel cost for that same change in the ratio is higher, then the TE system has lower costs. If the change in that ratio is lower, or if the fuel cost is lower, the conventional system has lower costs. The two curves for 20 MW bases in the Southwest bound the curves for the other base sizes and climates.

Annual Cost of Steam Turbine TE Systems

The uniform annual costs of oil fired and coal fired steam turbine TE systems for a 40 MW base in the Southeast are shown in Figure 28. For comparison, the costs of oil fired multiple unit diesel and gas turbine TE systems are also shown. The oil fired steam turbine system costs more than the diesel or gas turbine systems. The higher fuel savings of the steam turbine in this size range in colder climates, would make it more competitive there. The higher capital costs for a coal fired system--both for the electric generation system and the auxiliary hot water generator--result in higher total costs for the coal fired systems than for oil fired systems, if the prices are the same for the two types of fuel. However, lower prices for coal than for oil could result in a lower total annual cost for a coal fired system.

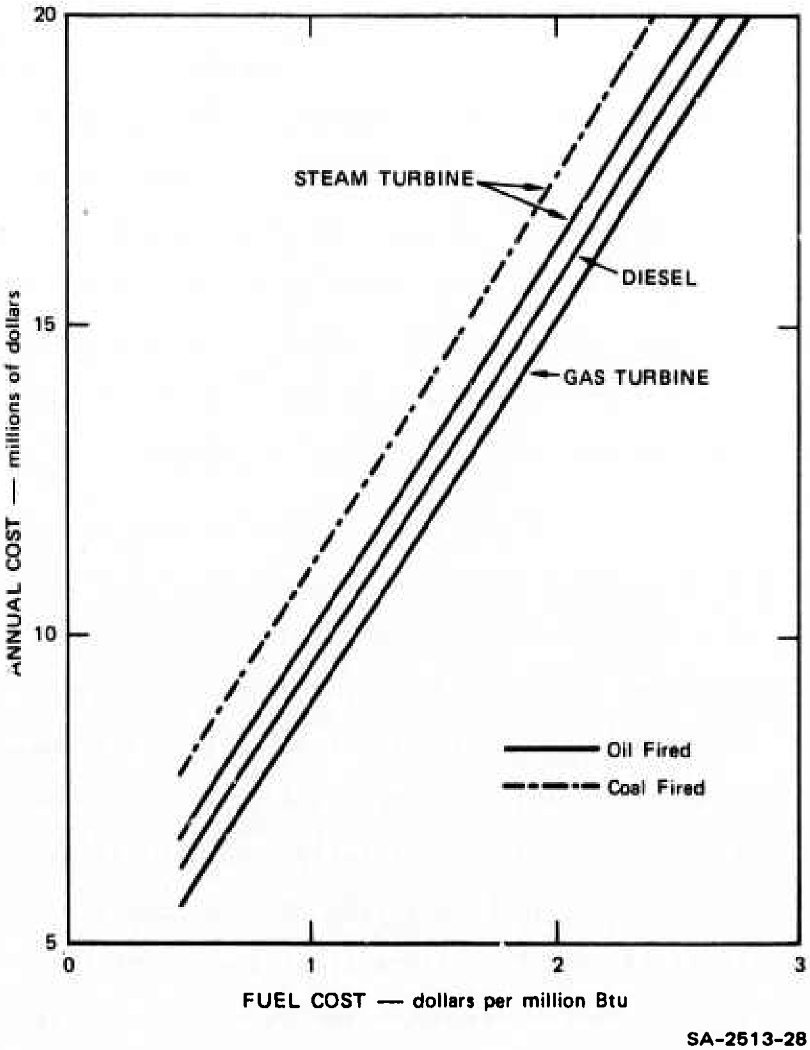


FIGURE 28 ANNUAL COST VERSUS FUEL COST OF OIL AND COAL FIRED TE SYSTEMS—SOUTHEAST, 40 MW BASE

Annual Cost of Single Unit Gas Turbine TE System

The costing and cost comparisons for the single unit gas turbine concept are complicated by the generation of excess electricity: the system costs are dependent on the price received for that electricity. Figure 29 shows the total annual cost of a single unit 40 MW gas turbine TE system for a 20 MW base in the Southeast. The cost allows a credit for the excess electricity equal to the cost of fuel for the utility to generate the electricity. In one case the fuel cost to the utility is assumed to be the same as the fuel cost for the TE system. In another case the fuel cost to the utility is assumed to be half the cost of fuel for the TE system, which might happen if the utility is using coal at half the price of the fuel oil used by the TE system.

For comparison, the annual cost of a conventional system is also shown. The electric energy charge is assumed to be 0.5¢ per kWh plus the cost of the fuel for generating the electricity, where the utility is paying either the same price for fuel as the base is paying or else half that price. If the utility is paying the same price for fuel, and if the TE system is given credit for the excess electric at the cost of the fuel used by the utility to generate electricity, then the TE system has lower costs. However, if the utility is paying half as much for fuel as the base, and if the credit for the excess electricity from the TE system is related to that lower fuel price, then the TE system has higher costs.

Effect of Heat Transmission Line Length on Cost Comparisons

To avoid introducing another parameter, which would have multiplied the number of cases to be analyzed, only one hot water line length was assumed for each of the base sizes. As illustrated earlier in Figure 13, the cost of the hot water lines is a major element of the capital costs. In addition, the small heat loss in the hot water lines is actually significant relative to the energy savings provided by a TE system.

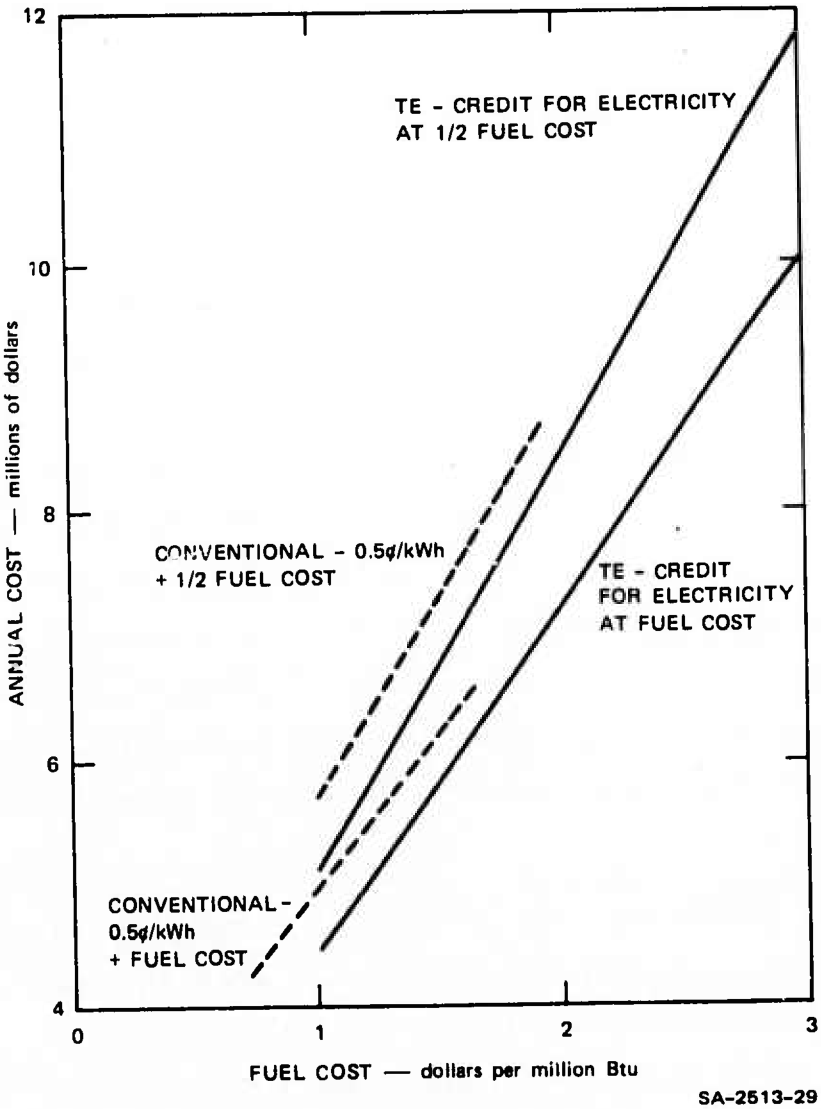


FIGURE 29 ANNUAL COST VERSUS FUEL COST OF 4υ MW GAS TURBINE TE AND CONVENTIONAL SYSTEMS— SOUTHEAST, 20 MW BASE

To indicate the effect of line length, Figure 30 shows the annual cost of a diesel TE system for a 5 MW base in the Southeast, for hot water line lengths varying from zero to two miles. The annual costs are shown excluding fuel, and also with fuel at $1 or $3 per million Btu. As the figure indicates, the effect of variations in line length is small relative to the total annual cost.

The annual cost of a conventional system, excluding fuel and electricity, is also shown in Figure 30. This system does not have hot water lines (except those within the complexes, which have been excluded from the analysis). The cost at the zero line length point represents a case of a base consisting of a single complex, with a single centralized plant for the hot water generators. The cost at the two-mile line length point represents the case of a base consisting of four complexes, with separate hot water generator plants in each complex. The single centralized hot water generator plant costs less because of the economies of scale; this cost reduction for the centralized plant is approximately the same as the cost of the two miles of hot water lines in the TE system. Thus the hot water line cost has little effect on the relative costs of TE and conventional systems.

In a TE system, the zero hot water line length case represents an installation in a single complex on a larger base. The comparisons between TE and conventional systems for a multi-complex base are also roughly applicable to the single complex case. For smaller complexes than the 5 MW size, the fuel efficiency of the TE system will be less and the fuel savings will be reduced.

Fuel Price Growth

The previous figures on annual costs have included for fuel costs (and the electric energy charges) the uniform annual cost of fuel over the 25-year system life. Thus the changing prices of fuel over the period

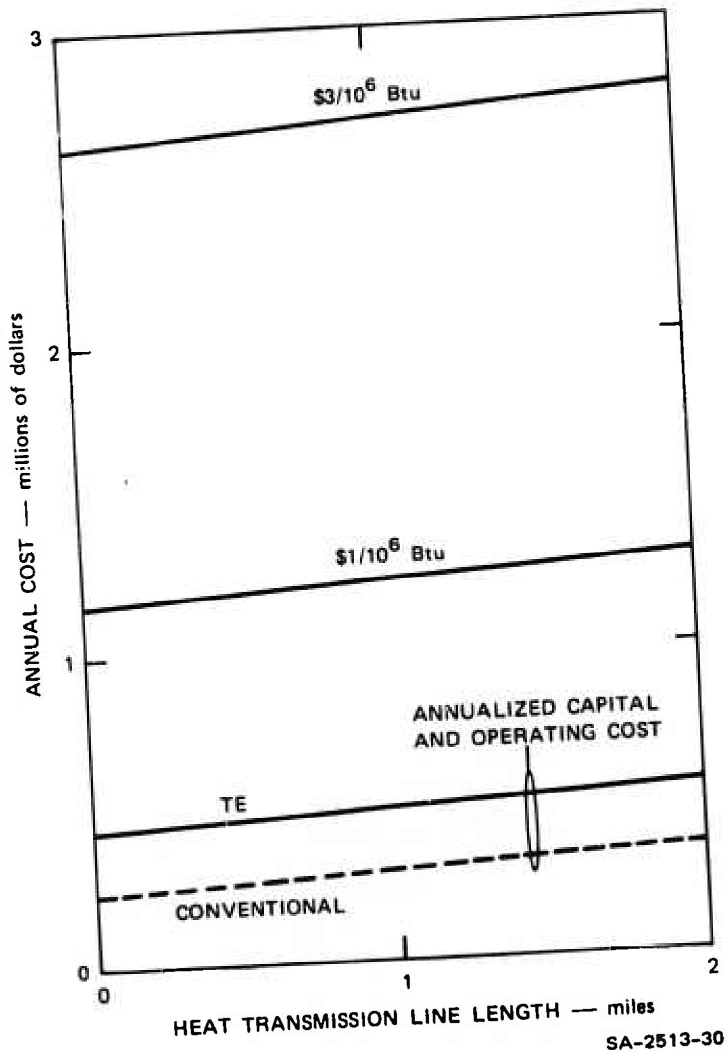


FIGURE 30 EFFECT OF HEAT TRANSMISSION LINE LENGTH IN DIESEL TE SYSTEM—SOUTHEAST, 5 MW BASE

are converted to a single price. This section indicates how the uniform annual cost of the fuel is related to changes in fuel price over the period.

Figure 31 illustrates three possible types of fuel price growth curves. The three curves assume that the fuel price increases (in constant dollars) by a factor of three over the 25 years. The exponential growth curve assumes a constant percent increase in price each year. The constant amount curve assumes that the price increases by a constant dollar amount each year. The third growth curve assumes that the fuel price increases by a constant amount each year for ten years, with no further

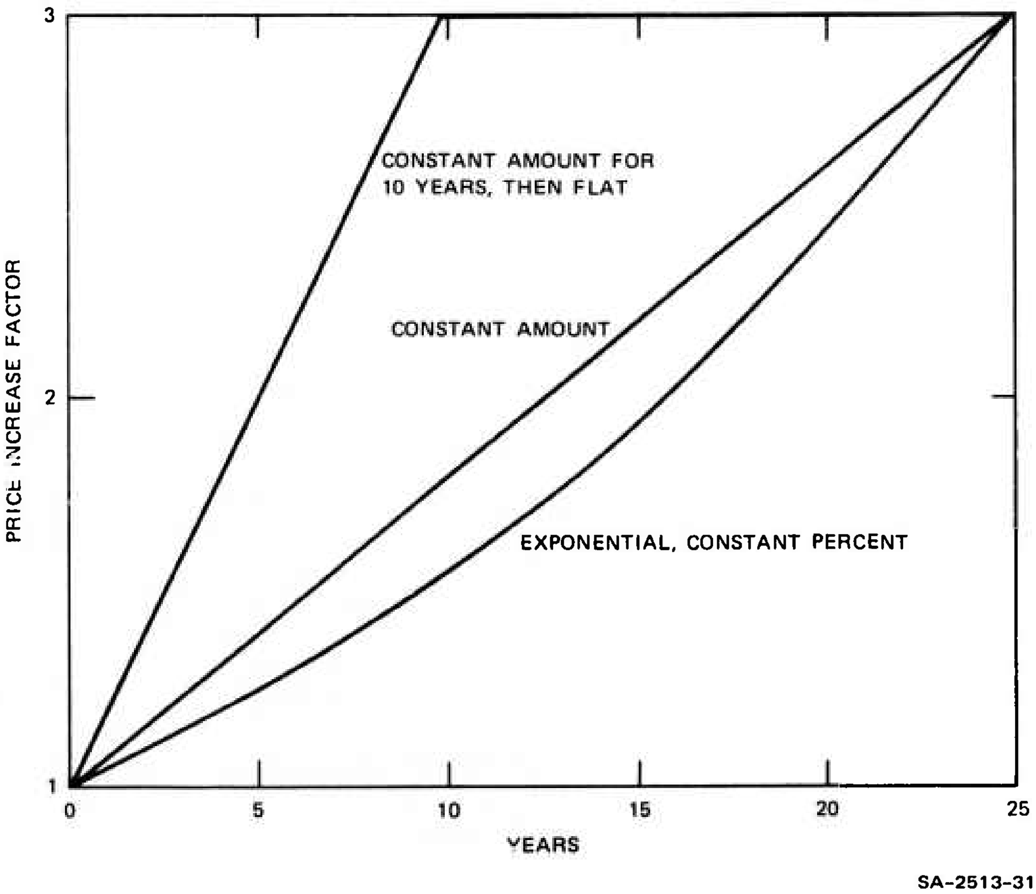


FIGURE 31 THREE POSSIBLE TYPES OF FUEL PRICE GROWTH CURVES

change after that. This last growth curve might represent a scenario in which prices increase only until technological developments such as coal gasification or utilization of shale oil become economical, after which the expanded supply of fuel permits stable prices for the remainder of the 25 years.

Figure 32 relates the increase factor in the uniform annual cost to the price factor over the 25-year period, for the three growth curves and at the 6-1/8 percent discount rate. With the exponential growth curve, if the price increases by a factor of five over the 25-year period, then the uniform annual cost would be 2.1 times the present cost.

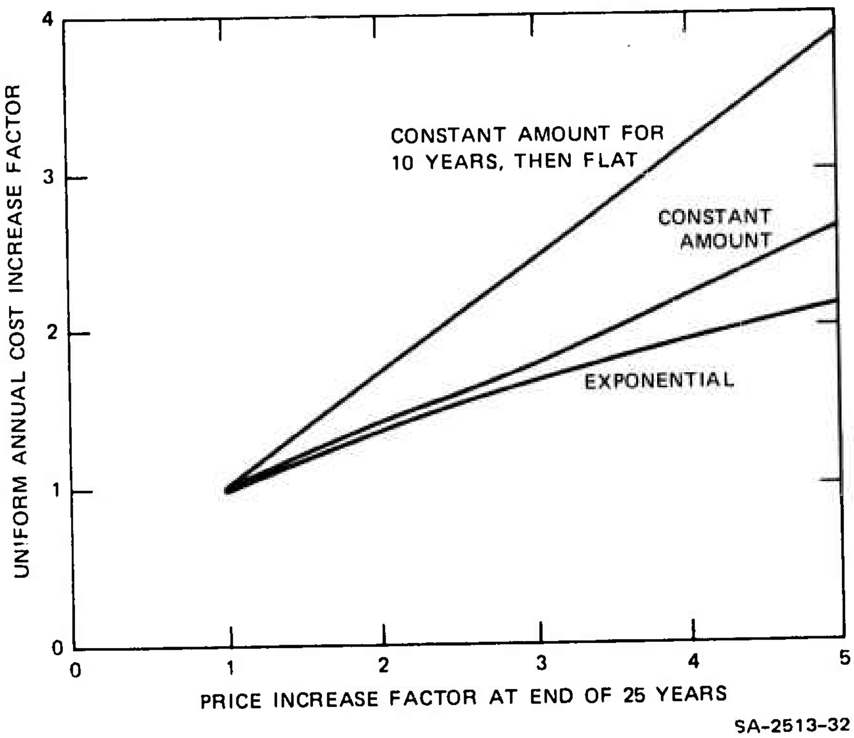


FIGURE 32 UNIFORM ANNUAL COST INCREASE FACTOR VERSUS PRICE INCREASE FACTOR OVER 25 YEARS

VI GEOTHERMAL SYSTEMS

The applicability of geothermal energy to military installations is dependent on both the availability of geothermal sources and the costs of geothermal energy systems. This section of the report identifies the bases that have geothermal potential, and gives examples of the costs of geothermal systems for two types of sources. Appendix D describes the several types of geothermal sources and gives details of the geothermal systems for the two applications studied.

Military Installations with Geothermal Potential

The types of geothermal resources considered in this study include (1) dry steam, (2) hot water, and (3) geopressure. Dry, hot rock resources were excluded since they are not well defined at present.

The identification of installations located within known geothermal resource areas or in areas of geothermal potential relied upon two basic references: (a) the Army Topographic Command's map of DoD installations by service in the United States,* and (b) the U.S. Geological Survey's data on known geothermal resource areas.+ Data on the peak 1972 electric demand for selected bases were derived from facilities engineering reports of the individual services. The number of bases so identified are only representative, as it is not clear from present data whether geothermal resources might actually be found for bases in potential geothermal areas.

---

* Army Topographic Command, "Major Army, Navy, and Air Force Installations in the United States," Map No. 8205x MILINST*35 (February 1971).

+ U.S. Geological Survey, "Classification of Public Lands Valuable for Geothermal Steam and Associated Geothermal Resources," Circular 647 (1971).

Preceding page blank

Figure 33 shows the location of potential geothermal resources in the United States applicable to military installations. Similar information for U.S. military installations outside the United States is shown in Figure 34.

Table 8 summarizes the number of bases in the continental United States (CONUS) for each service that are located at potential geothermal sites for hot water/steam and geopressure systems. There are 16 active sites located in hot water or steam areas, and 17 sites in possible geopressure areas. The total number of bases in geothermal regions is about 8 percent of the total in the CONUS. The Navy has the largest percentage of bases with geothermal potential, most of them in geopressure regions.

Table 9 identifies the military installations in CONUS with potential geothermal hot water resources, and lists the peak electric demand for each base. Table 10 gives the same information for geopressure resources. Many of the bases located in areas that appear to possess geothermal potential have relatively small energy loads: only four of the bases with potential water resources and four with potential geopressure resources have a peak electric demand over 7 MW. However, much remains to be learned about geothermal resources. Energy derived from such sources would provide a valuable contribution to energy supply for military installations.

Costs of Geothermal TE Systems

Two examples are given of the costs of geothermal applications to military installations. The examples assume a base with a 20 MW peak electric rate and a Southeast type energy load pattern. One case is for a dry steam geothermal source, and the other is for a hot water source.

For the dry steam system, the steam is used for generating electricity and also directly for the thermal load. Heat recovery from the electric generation was not included so as to have higher electric generation

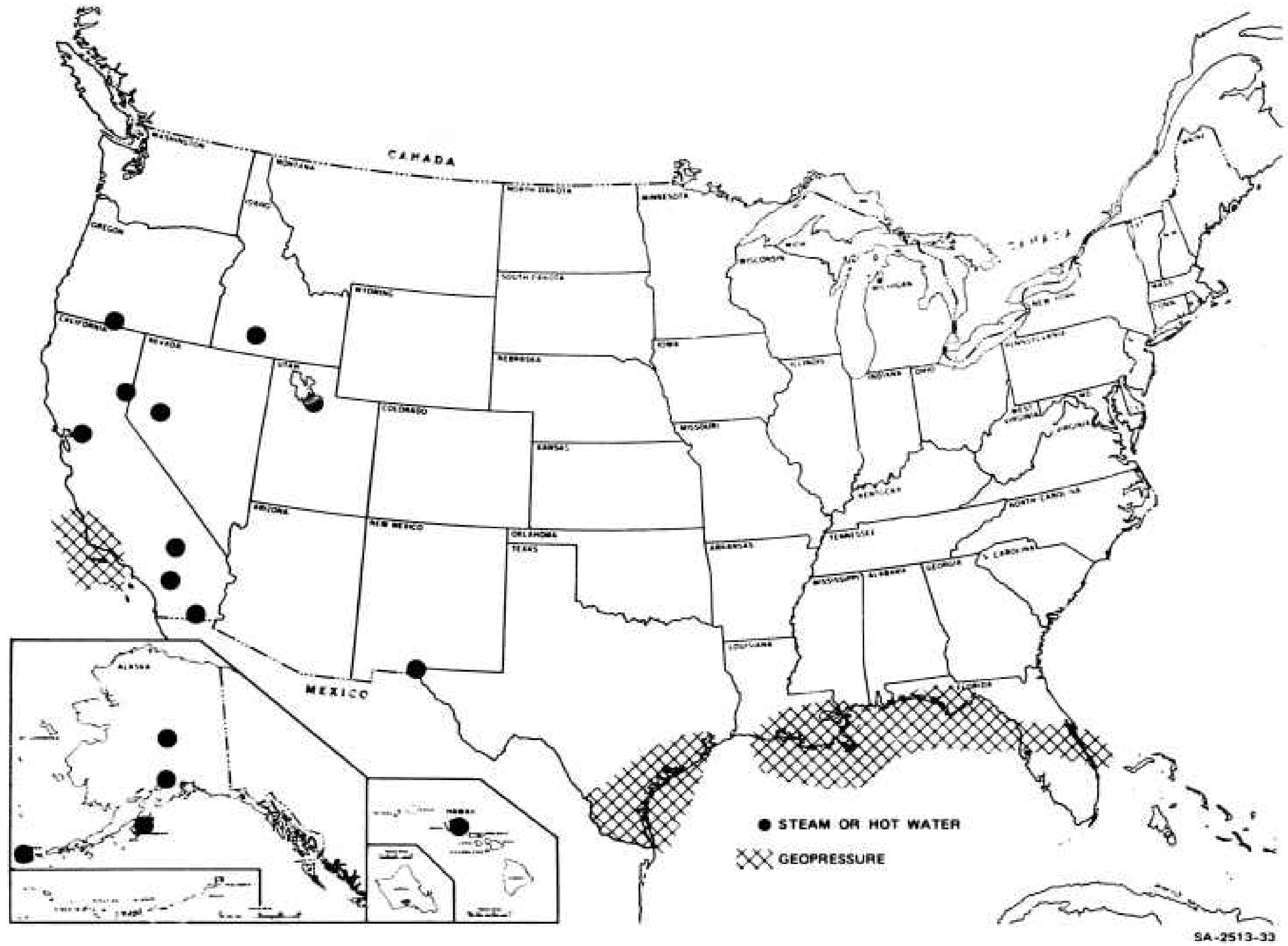


FIGURE 33 POTENTIAL GEOTHERMAL SITES FOR MILITARY INSTALLATIONS IN THE UNITED STATES

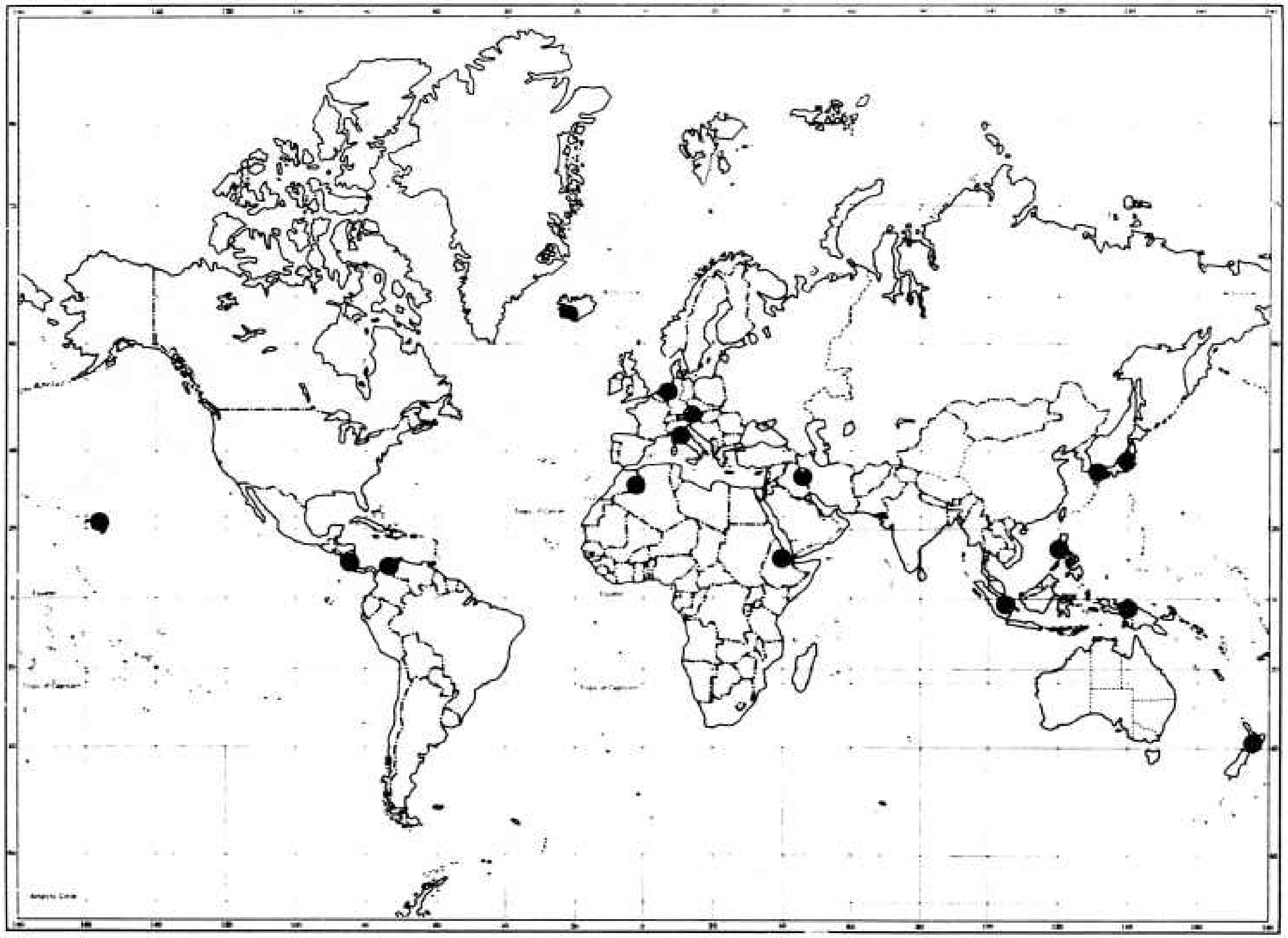


FIGURE 34 POTENTIAL GEOTHERMAL SITES FOR U.S. MILITARY INSTALLATIONS OUTSIDE THE UNITED STATES

Table 8

NUMBER OF CONUS BASES AT POTENTIAL GEOTHERMAL SITES

	Army	Navy	AF	Total
Hot Water				
Active	6	4	6	16
Inactive	2	0	1	3
Geopressure	0	10	7	17
Total number	8	14	14	36
As percent of CONUS bases	5%	14%	7%	8%

Table 9

MILITARY INSTALLATIONS IN THE UNITED STATES
WITH POTENTIAL GEOTHERMAL HOT WATER RESOURCES

Service	State	Base	Peak Electric Demand (MW)
Army	California	Sierra Army Depot	1.8
	Utah	Utah Army Depot	n.a.
		Toole Army Depot	4.6
	Texas	Ft. Bliss	23.6
Navy	California	El Centro Air Facility	3.2
		China Lake	21.3
	Nevada	Fallon Aux. NAS	1.7
Air Force	California	Norton AFB	19.0
		March AFB	14.8
	Oregon	Kingsley Field	1.6
	Idaho	Mt. Home AFB	5.8

Table 10

MILITARY INSTALLATIONS IN THE UNITED STATES
WITH POTENTIAL GEOPRESSURE RESOURCES

Service	State	Base	Peak Electric Demand (MW)
Navy	Texas	Kingsville NAS	0.9
		Chase Field NAS	0.5
	Louisiana	New Orleans NAS	0.4
	Mississippi	CB Gulfport	0.8
	Florida	Pensacola NAS	5.3
	California	CB Pt. Hueneme	6.8
		PMR, Pt. Mugu	12.6
Air Force	Texas	Laredo AFB	6.1
		Ellington AFB	6.4
	Mississippi	Keesler AFB	32.6
	Florida	Eglin AFB	54.8
		Tyndall AFB	13.5

efficiency and also so that the heat distribution and applications could be at a high temperature. For the hot water system, steam was separated and flashed from the hot water. The steam was used to generate electricity, also without heat recovery, and the hot water for the thermal loads.

The major categories of geothermal system costs include exploration, drilling, wellhead equipment, collection pipework, electric power plant, heat exchangers, hot water transmission lines, and air conditioning. Explicit consideration was not given to the costs of dealing with extreme cases of corrosives or the presence of large amounts of salts or solids.

The uniform annual cost of the geothermal system compared with a conventional system is shown in Figure 35. An electric energy charge of

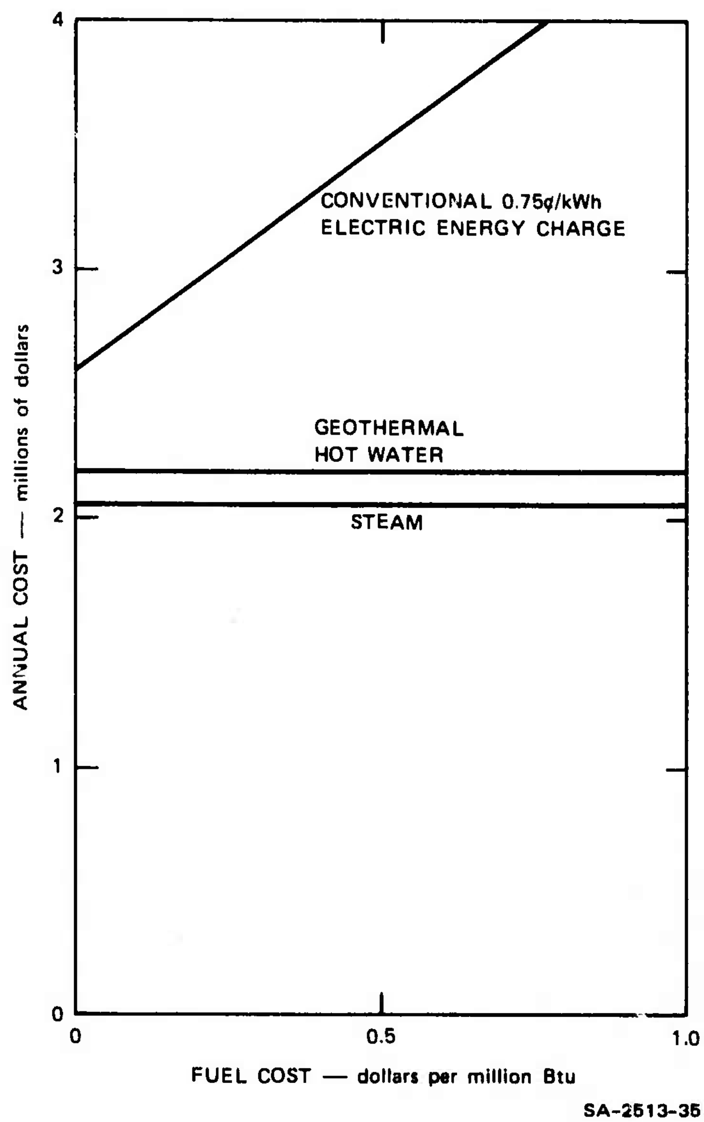


FIGURE 35 COMPARISON OF COSTS FOR GEOTHERMAL AND CONVENTIONAL SYSTEMS—SOUTHEAST, 20 MW BASE

0.75¢ per kWh was assumed for the conventional system. The geothermal system cost is lower than that for a conventional system, even if conventional fuel were free. The costs of the hot water heat transmission lines and the air conditioning constitute nearly half the annual cost of the geothermal systems. Thus, even doubling the geothermal related costs to account for problems with salts and corrosives, and environmental protection, would still leave the geothermal systems economically attractive. The principal problems remain in locating the geothermal resources and in carrying out the research and development required to achieve practical and economical operations.

VII SOLAR ENERGY

System Concepts

The solar energy analysis was limited to two types of systems, both utilizing flat plate collectors. One system uses solar energy only for heating and cooling, the other for generating electricity as well as for heating and cooling.

The system providing only heating and cooling operates with water as the collecting medium at temperatures just below the boiling point, e.g., 207°F. The flat plate collectors have a selective coating providing a moderate emissivity of 0.2. Thermal storage is by hot water.

The system providing electricity also, operates at about 350°F. This temperature is about the maximum attainable without going to focusing systems with the attendent solar tracking complexities. The flat plate collectors have a selective coating providing a low emissivity of 0.05. Heat is recovered from the electric generation at the relatively high temperature of 190°F and is used for the heating and cooling loads. Setting this outlet temperature reduces the electric generation efficiency to only 12 percent. However, low efficiency of electric generation is consistent with meeting thermal loads several times as high as the electric loads.

For both types of systems, separate units were assumed in each complex, rather than a single centralized system for the base with the attendent requirement for hot water lines between the complexes.

Additional details of the solar energy concepts is given in Appendix E.

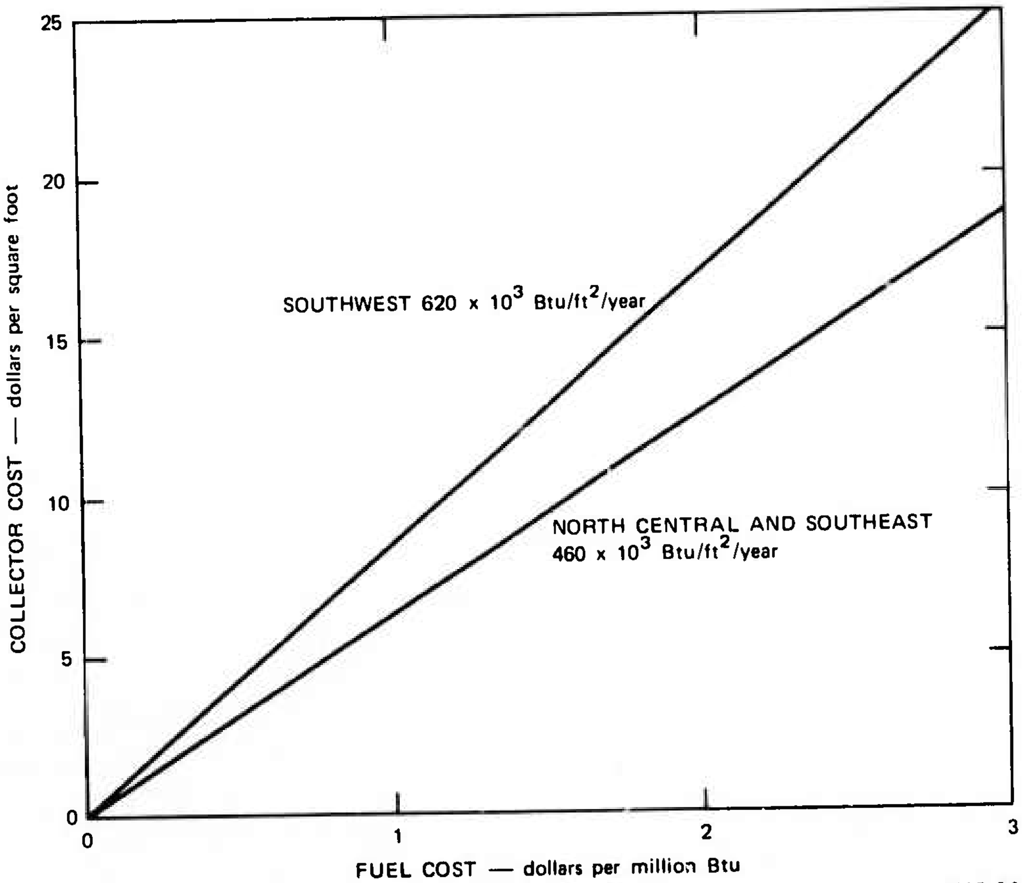
Solar Insolation

Solar insolation data are available from a number of weather stations, some providing daily data and others hourly data. The stations record the "hemispheric solar radiation" which is the total irradiance, direct and diffuse, upon a horizontal surface. (One reason for the selection of flat plate collectors was their ability to utilize the diffuse as well as the direct radiation.) The calculations of solar energy collection for this study were based on the frequency distribution of daily insolation from a few stations in each of the three climatic regions--North Central, Southeast, and Southwest.

The collectors were assumed to be tilted to an angle with the horizon of 10° more than the latitude. The tilt angle compensates for the difference in the elevation of the sun between summer and winter, so that there is little seasonal variation in heat collected except that due to differences in cloud cover. Heat collection efficiency was calculated as a function of the daily insolation.

Collector Costs

The costs of solar collectors are still uncertain but as fuel costs increase, the allowable collector costs for economically competitive solar energy will also increase. Figure 36 shows how much the collectors could cost and still be economically competitive with fuel-consuming systems, as a function of the cost of fuel. Two curves are shown: one for the Southwest where 620,000 Btu per sq ft of collector can be collected annually, and one representing the other two climates with 460,000 Btu per sq ft collected annually. The collector cost is here considered to include other costs of a complete system, such as distribution lines, pumps, heat exchanger, controls, coolant, frame and supports, and installation. The fuel cost refers to the uniform annual cost of fuel over a 25-year period. The figure also assumes utilization of all the heat collected.



SA-2513-36

FIGURE 36 ALLOWABLE SOLAR COLLECTOR COST AS A FUNCTION OF FUEL COST

The allowable collector costs are strongly dependent on the discount rate which is here 6-1/8 percent. A higher discount rate would reduce the allowable collector costs.

Figure 36 shows that with fuel costs of $1.50 per million Btu, a reasonable figure to expect, the allowable collector costs are between $9 and $12 per sq ft. Since collector costs after further development and in large-scale production, are not expected to be that high, solar energy appears likely to be economically feasible. For purposes of this study, collector costs of $3 or $6 per sq ft were used for the heating and cooling only system, and $4 or $8 per sq ft for the system that includes electric generation. These collector costs include the costs of other elements of a complete system as indicated on page 84.

Collector and Storage Sizing

If the collector is sized to meet the average energy load on an average insolation day, the variability in both energy load and insolation will result sometimes in excess heat being collected which cannot be utilized and at other times in a heat deficit requiring supplemental heat. To some extent the excess heat can be stored to meet the deficits, but the cost of storage limits the heat storage capacity. The economic optimum for collector size and thermal storage capacity depends on the costs of collectors, thermal storage, and fuel. With the uncertainties in these costs, optimization could only be parametric.

For purposes of this study, a limited set of collector and thermal storage sizes was selected and are illustrated in Figure 37. The figure shows the heat loads for each of the five representative days of the year, for a 10 MW base in the Southeast, in one case for heating and cooling only, and in the other case for electricity generation as well as heating and cooling. In the latter case, the heat load is set by the electric load, with the other thermal loads met from the heat recovery, except

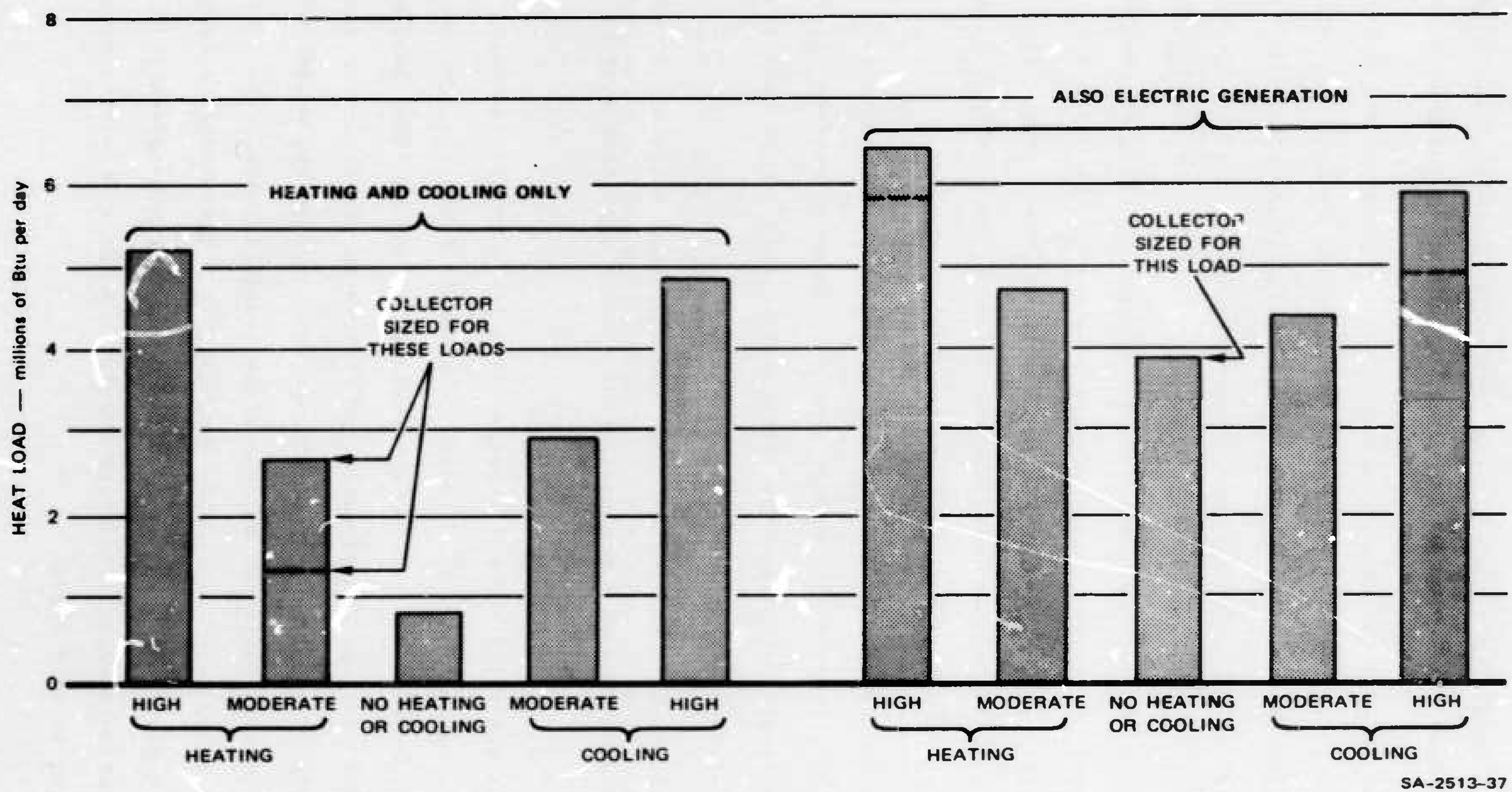


FIGURE 37 HEAT LOADS FOR FIVE REPRESENTATIVE DAYS AND RELATIONSHIP TO SOLAR COLLECTOR SIZING—SOUTHEAST, 10 MW BASE

for the high heating and high cooling days where there is a small additional heat load (indicated by the dashed lines) above the heat recovery.

For the heating and cooling only system, two sizes of collector were selected. In one case the collector was sized to meet the thermal load on a moderate heating day with average solar insolation. On the high heating and high cooling days, even with higher than average insolation most of the heat collected can still be utilized and supplemental energy will usually be necessary. On the no space heating or cooling days, the minimum thermal load can usually be met by the collectors even with below average insolation, and there will be excess heat collected. On days with thermal loads between these extremes, there may be either a deficit or an excess of heat collected.

In the second case of heating and cooling only, the collectors were sized to meet only half the thermal load on a moderate heating day, with average insolation. In this case there will be less excess heat wasted but more supplementary heating will be required.

For the electric generation case, the collector was sized to meet the thermal load on a no space heating or cooling day, with average insolation.

The collector and thermal storage sizes for each of the cases, and the three climates, for a 10 MW base are given in Table 11. The term "medium collector" refers to the collector sized for the heat load on a moderate heat day, and "small collector" refers to the collector sized for half that heat load. The thermal storage was sized in all cases to hold 1.5 times the heat collected on an average insolation day. The thermal capacity is based on a temperature drop of 50°F. The storage size for the electric generation case is also based on water storage--although the higher temperature would require pressurization and alternative storage mediums might be preferable.

Table 11

SOLAR COLLECTION AND STORAGE SIZES--10 MW BASE*

	Collector Size (million sq ft)	Thermal Storage (million cu ft)
Heating and cooling, small collector		
North Central	1.26	0.82
Southeast	1.22	0.68
Southwest	0.71	0.59
Heating and cooling, medium collector		
North Central	2.52	1.63
Southeast	2.44	1.35
Southwest	1.42	1.18
Heating, cooling, and electric generation		
North Central	2.44	1.94
Southeast	3.29	1.94
Southwest	2.29	1.94

*The building floor area is eight million sq ft; one million sq ft equals 23 acres.

The building floor area for a 10 MW base is typically about 8 million sq ft. Thus the collector size ranges from about 10 to 40 percent of the floor area.

Because of the low grade heat provided by the collectors in the heating and cooling only case, a low efficiency--coefficient of performance of 0.5, which means 24,000 Btu per ton-hr--was assumed for the absorption air conditioning. The electric generation case, with higher operating temperatures, was assumed to use conventional absorption air conditioning requiring 18,000 Btu per ton-hr. For the case with the smallest size collectors, in the Southeast and the Southwest, about half of the air conditioning was assumed to be electric since the collectors provide insufficient heat for full absorption air conditioning.

Fuel Savings

The fuel consumption to supplement the solar energy collection, and the fuel savings compared with a conventional system are given in Table 12. As before, the fuel consumption for the conventional system consists of the fuel consumed on base for heating, plus the fuel used by the utility to generate the electricity consumed by the base, based on a heat rate of 10,000 Btu per kWh. For the solar energy system with heating and cooling only, the fuel consumption consists of the fuel consumed on base to supplement the solar heat, plus the fuel used by the utility for the electricity. For the solar system with electric generation, the fuel consumption consists only of the fuel consumed on base to supplement the solar heat, and used to generate electricity or directly for heat purposes.

The small collector case saves about a fourth of the fuel consumed by the conventional system and the medium collector case saves about 45 percent, except for the Southwest. That exception is due to the use of only absorption air conditioning. The thermal load for the absorption

Table 12

SOLAR ENERGY FUEL SAVINGS--10 MW BASE

	North Central	Southeast	Southwest
Fuel Consumption Btu X 10^{12}			
Conventional	2.17	1.63	1.41
Solar heat only			
Small collector	1.61	1.21	1.10
Medium collector	1.19	0.92	1.07
Solar electric	1.14	0.67	0.63
Fuel savings - percent			
Solar heat only			
Small collector	26%	26%	22%
Medium collector	45	44	24
Solar electric	47	59	55

air conditioning is too high for the amount of solar heat collected and burning fuel for absorption air conditioning is less efficient in fuel use than use of electric air conditioning. Use of electric air conditioning for part of the load would have increased the fuel savings. The fuel savings for the electric generation case are somewhat higher.

These figures on fuel savings do not represent the maximum savings attainable, since larger sizes of collectors and storage would increase fuel savings. However, the larger sizes would increase capital costs, and the economic optimum should be substantially short of 100 percent fuel savings.

Cost of Solar Energy

The total annual cost of the solar energy system for heating and cooling only consists of the capital costs for solar collectors, thermal storage, auxiliary heating, and air conditioners, operating and maintenance costs, fuel costs, and electricity charges. As previously mentioned, collector costs of \$3 or \$6 per sq ft were assumed. Large hot water tanks for thermal storage were assumed to cost \$1 per cu ft.

For the electric generation case the cost elements are the same except that an electric generating plant is added and the electric charges are dropped. The electric generating plants, including the heat recovery system, were assumed to cost \$500 per kW of capacity. Collector costs of \$4 or \$8 per sq ft were assumed. No specific type of thermal storage was adopted but for costing purposes, a cost equivalent to \$2 per cu ft for hot water storage with a 50°F temperature drop was assumed.

Figure 38 shows the total annual cost of a solar energy system with the medium size collector for heating and cooling only, for a 10 MW base in the North Central climate, and two assumed unit collector costs. The annual cost is shown as a function of the fuel cost. The cost of a conventional system is shown for comparison. For the electric energy charges, it was assumed for both the solar and conventional systems that the fuel cost element of the electric energy charge was the same as the fuel cost to the base. Since both systems purchase comparable amounts of electricity, variations in this cost element would have little effect on the cost comparisons.

The figure shows that with costs of conventional fuel already near \$1 per million Btu, the solar energy system would cost less than a conventional system if collector costs are \$3 per sq ft. Even if collector costs are \$6 per sq ft, the solar energy system would be lower in cost if the uniform annual cost of fuel is \$1.20 per million Btu or more.

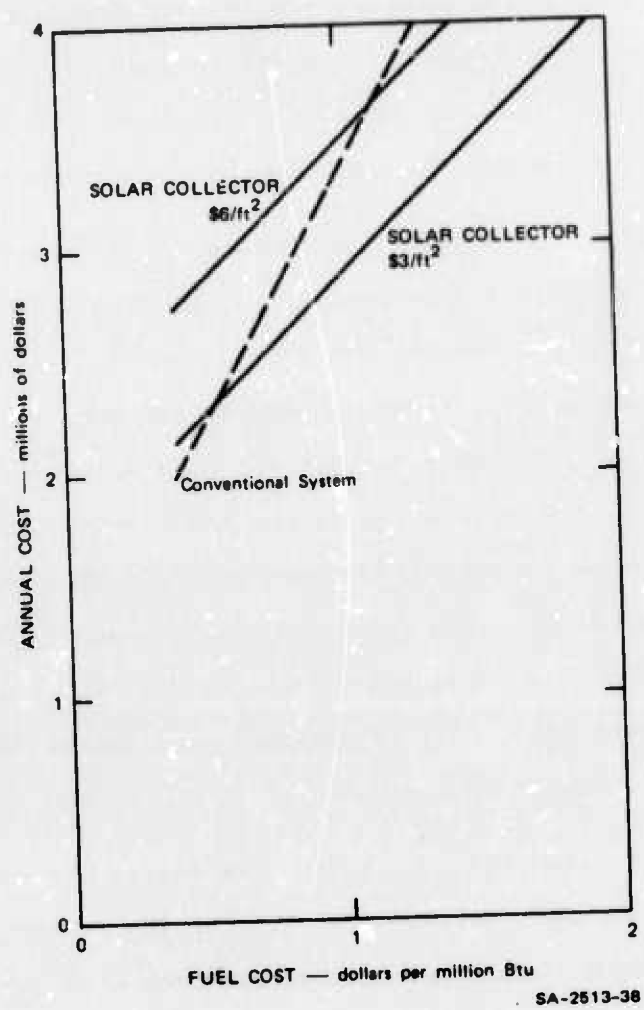


FIGURE 38 COST OF SOLAR ENERGY FOR HEATING AND COOLING—NORTH CENTRAL, 10 MW BASE

Figure 39 shows the annual cost of a solar energy system that includes electric generation. The annual cost of a conventional system shown for comparison includes two variations in the fuel cost element of the electric energy charge. If the collector costs are $4 per sq ft, the solar energy system would be economically competitive even with little further increase in fuel costs. However, if collector costs are $8 per sq ft, the break-even points for fuel costs range from $1.70 to $2.50 per million Btu, depending on the electric energy charge.

The annual costs for both types of solar energy systems for a 10 MW base in the Southeast are shown in Figure 40. The cost curves for the heating and cooling only system are labeled "heat," with the assumed collector cost per sq ft. These two curves are for the medium size collector, i.e., sized to meet the thermal load on a moderate heating day. The dashed lines crossing the two curves are for the small size collector, i.e., half the collector area of the medium case. The crossing points indicate the fuel cost points for equal annual costs of the two sizes of collector. For lower fuel costs, the smaller collector size will have a lower annual cost, while for higher fuel costs, the larger collector size will have the lower cost.

The fuel cost elements of the electric energy charge for the solar system with heating and cooling only, and for the conventional system shown for comparison, are based on the same fuel cost to the utility as the base is paying. Comparisons between these systems will be little affected by variations in the electric energy charge since the electricity usages are comparable. However, a lower fuel cost element in the electric energy charge would reduce the slope of the curves and improve their position relative to the solar system with electric generation.

The annual costs of the two types of solar energy systems for the Southwest are shown in Figure 41. For the heating and cooling only

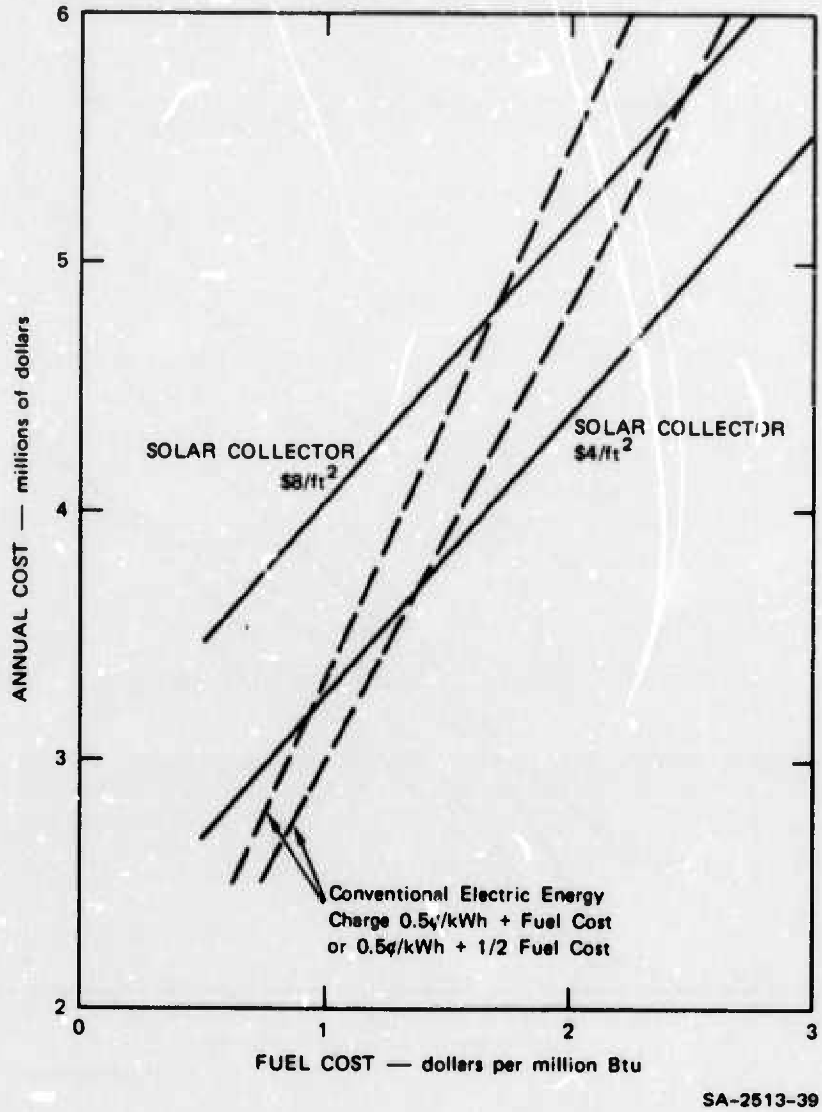


FIGURE 39 COST OF SOLAR ENERGY FOR ELECTRIC GENERATION—NORTH CENTRAL, 10 MW BASE

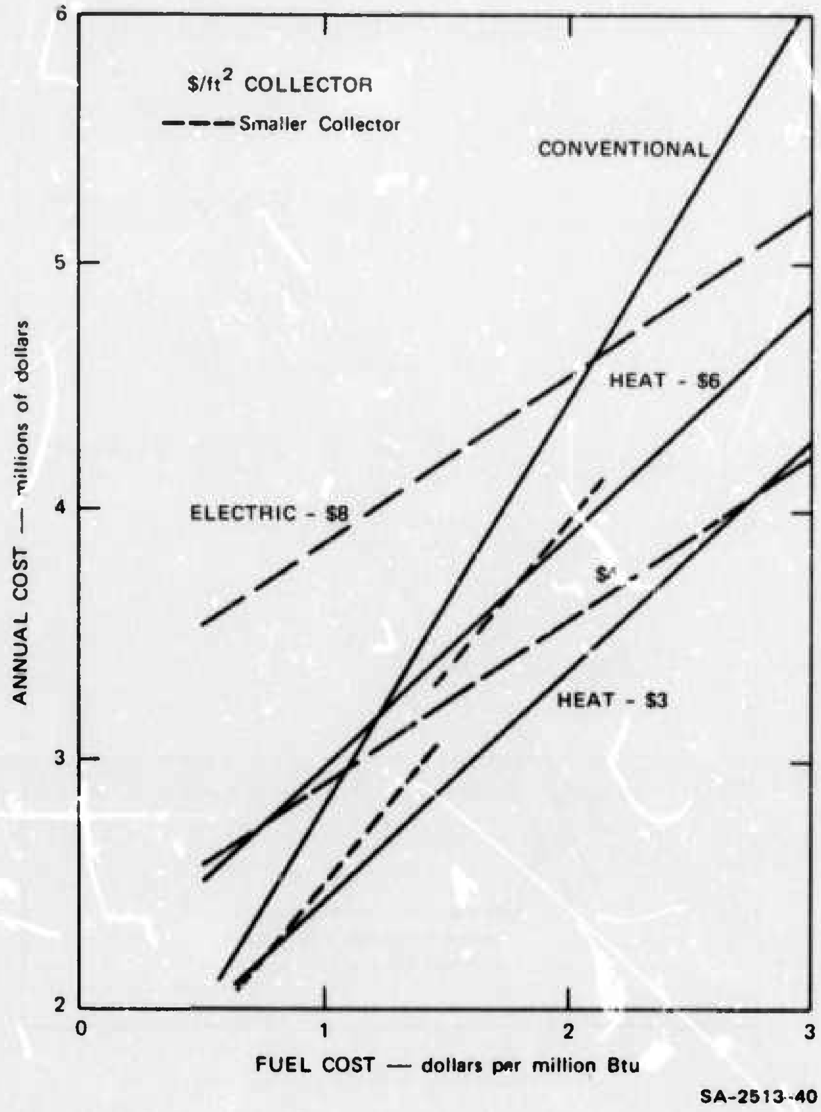


FIGURE 40 COST OF SOLAR ENERGY—SOUTHEAST, 10 MW BASE

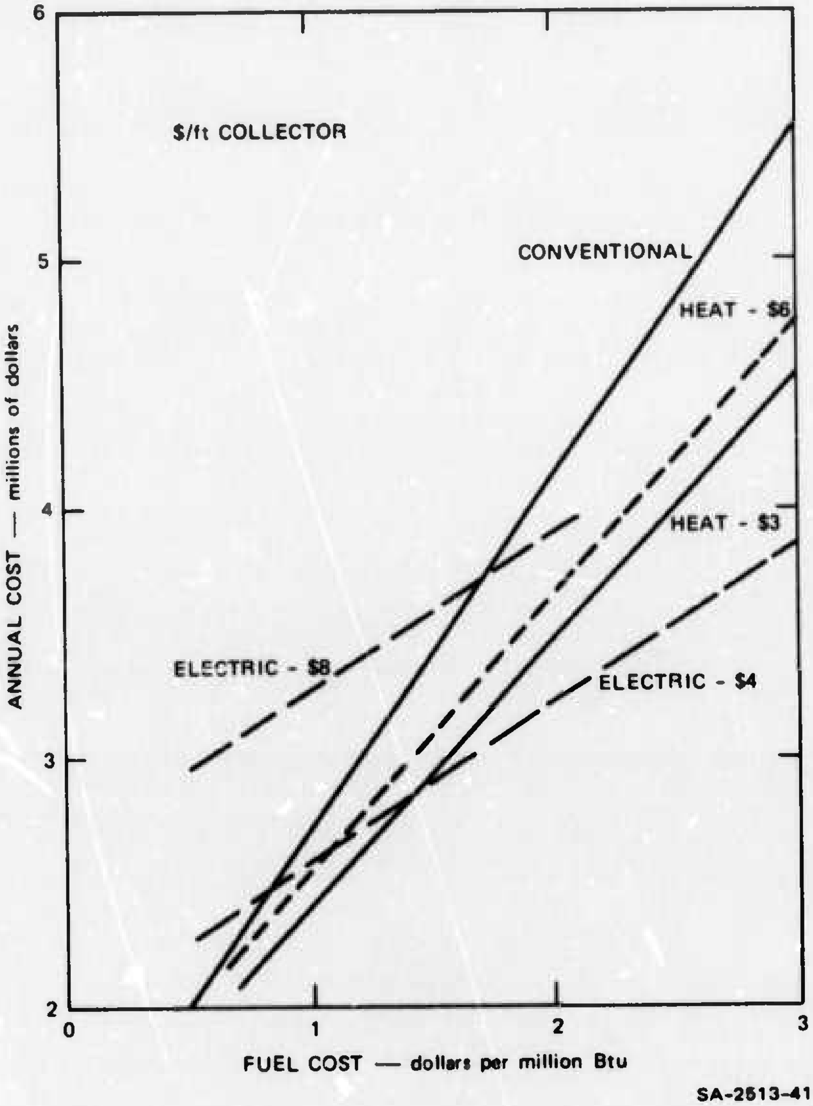


FIGURE 41 COST OF SOLAR ENERGY—SOUTHWEST, 10 MW BASE

system, with collector costs of $3 per sq ft, the annual costs are approximately the same for the two collector sizes. However, with collector costs of $6 per sq ft, the smaller size collector has lower total costs (the $6 curve in Figure 41 is for the smaller collector).

VIII NUCLEAR POWER

The feasibility of application of nuclear power for the larger military installations was investigated. The nuclear power plant was considered to be located on base so as to be able to supply thermal energy as well as electricity.

There has been little development or study of nuclear power plants in the size range applicable to large military installations. Nuclear power plants for utilities are now in the 1000 MWe range. The Army Nuclear Power Program considered principally small nuclear power plants of a few MWe or sub-MWe capacity, although the nuclear power barge studies involved capacities approaching that required for large military installations. The prototype high temperature gas cooled reactor (HTGR) of Gulf General Atomic is also near that capacity.

Environmental and safety considerations for locating nuclear power plants on military installations were not addressed in this study.

Plant Size

For purposes of plant sizing and heat recovery modeling, the thermodynamic characteristics of the HTGR, which has higher initial steam temperatures than the light water reactors, were assumed. Because the typical turbine throttle steam conditions of the HTGR closely match the throttle conditions assumed for fossil fuel steam turbines described in Appendix A, the same heat rate and heat recovery model can be used for the HTGR.

A single case is considered of a base in the Southeast with a peak electric rate of 20 MW. The peak thermal load is 140 MWt. The maximum heat recovery rate is 7 MWt per MWe, which is the same as the ratio of peak thermal load to peak electric load. The heat rate at maximum heat recovery is 10 MWt per MWe; thus the required plant capacity is 200 MWt. For the largest bases in the colder climates, the required capacity could be up to about 500 MWt.

Costs

In the absence of recent information on nuclear power costs for the desired size range, extrapolations were made from the 1967 AEC report on "Small Nuclear Power Plants."* With a 30 percent efficiency for the boiling water reactor costed in that report, the equivalent electrical capacity for a 200 MWt plant would be 60 MWe. By interpolation, the 1966 capital cost for a 60 MWe plant was $21.5 million. The costs of nuclear power plants have been increasing faster than the inflation rate or the construction cost index. Assuming an 80 percent increase in costs between 1966 and 1973, the 1973 cost would be $38.7 million. The annual operation and maintenance cost of $940,000 is assumed to increase by 50 percent to $1,410,000.

Additional capital costs for the heating plant needed when the nuclear plant is down, the air conditioning (double effect absorption type), and the hot water lines total $11.52 million. Fuel costs of 1 mil per kWht are assumed and 981 million kWht are required annually. An electric demand charge is included for utility electricity to meet the nuclear plant downtime. The total uniform annual cost is then as follows:

---

*U.S. Atomic Energy Commission, "Small Nuclear Power Plants," Volume 3 (March 1967).

Capital costs	
Nuclear	$38.70 million
Other	11.52
Total	$50.22
Annualized capital cost	3.98
Annual operation and maintenance	
Nuclear	1.41
Other	.16
Fuel	.98
Electric demand charge	.30
Total uniform annual cost	$ 6.83 million

This nuclear power cost is compared with the cost of a conventional system in Figure 42. Two curves are shown for the conventional system, with the fuel cost element of the electric energy charge based on, in one case, the same fuel price paid by the base, and in the other case, on half that price. The break-even point in fuel costs then ranges from $1.35 to $1.75 per million Btu, depending on the electric energy charge. Thus nuclear power for this case appears close to being economically competitive with conventional systems.

Since the nuclear plant would be designed for the peak electric and thermal loads, most of the time it would have substantial excess capacity. If this excess capacity is used to generate electricity to send off base, the credit for this electricity would improve the economics of nuclear power. Because of economies of scale, nuclear power would also be more favorable for larger bases than the 20 MW peak electric demand used for this example.

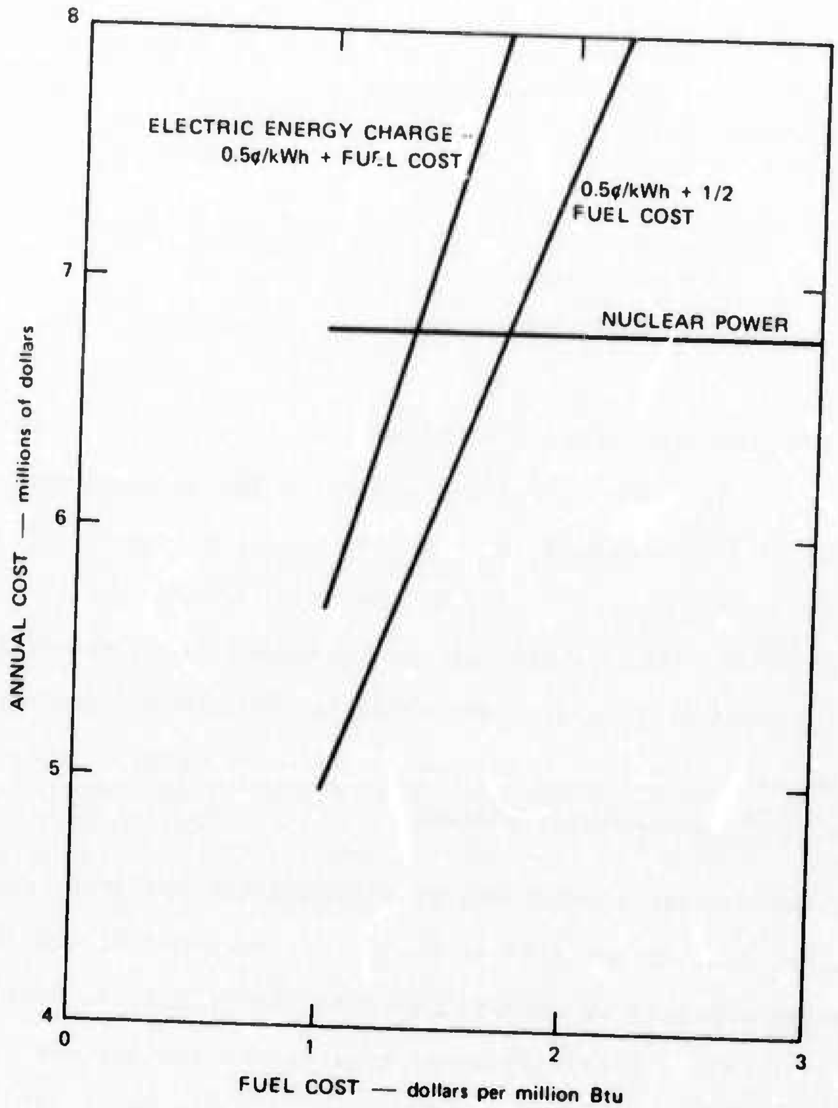


FIGURE 42 COMPARISON OF COSTS FOR NUCLEAR POWER AND CONVENTIONAL SYSTEMS—SOUTHEAST, 20 MW BASE

IX ENERGY FROM SOLID WASTES

The solid wastes produced on military installations are a significant potential source of energy. The burning of the wastes for energy would also alleviate disposal problems.

Table 13 shows the energy potential of solid wastes for a small selection of military installations. The information shown in the table that was obtained from facilities data includes the annual fuel consumption and the cubic yards of solid waste. The cubic yards of waste are converted to tons, assuming 350 lb per cu yd based on the average of 450 lb per cu yd for compactor-truck waste and 250 lb per cu yd for loose waste. The figures for energy content of the waste assume a heating value of 4000 Btu per lb, which is based on 20 to 30 percent moisture content and 95 to 99 percent burn of the combustible wastes, utilizing fluid-bed technology. Although the energy content of the wastes varies with the type of waste and the moisture content, the 4000 Btu per lb is considered conservative. For example, tests run on the recently operative St. Louis power plant which utilizes city refuse, indicate heating values of about 5000 Btu per lb. The fluid-bed technology--a pyrolysis fuel concept--is environmentally attractive.

The solid waste produced per capita on the military installations appears higher than the national average. Frequently quoted figures on national average per capita solid wastes are about 5 to 6 lb per day,*

---

*A. J. Muhich, A. J. Klee, and C. R. Hampel, "1968 National Survey of Community Solid Waste Practices," Public Health Service Publication No. 1866, Washington, U.S. Government Printing Office (1968).

Table 13

ENERGY FROM SOLID WASTES

Base	Annual Fuel Consumption Billion Btu	Annual Solid Wastes				Solid Waste Energy as Percent of Fuel Requirement
		Cu Yd Per Person	Thousands of Cu Yd	Thousands of Tons	Billions of Btu	
Fort Knox	2913	22	830	145	1162	40%
Fort Ord	1731	12	391	68	547	32
Travis	1020	14	237	41	331	32
Minot	1125	10	153	27	214	19
Offutt	1262	9	141	25	197	16
Loring	1457	9	101	18	141	10
Castle	356	12	73	13	102	28
Carswell	403	9	55	10	77	19

which on the basis of the above compacted density assumption is equivalent to about 5 to 6 cu yd per year. The higher figure for the military installations might be explained by higher amounts of packaging wastes and other types of administrative and industrial wastes, or possibly by more complete data.

As shown in the table, the solid wastes could provide 10 to 40 percent of the fuel requirements of the selected bases. (The fuel consumption figures are for the fuel used on base, and exclude fuel used by the utilities to produce the electricity consumed on the base.) In some cases the solid wastes could provide the fuel needed to supplement the energy provided by a solar energy system for heating and cooling.